OGCB REPORT 70-B

IN THE MATTER OF AN APPLICATION OF TRANS-CANADA PIPE LINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

1970

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OIL AND GAS CONSERVATION BOARD

603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

OIL AND GAS CONSERVATION BOARD
603 SIXTH AVENUE S.W. • CALGARY 1, ALBERTA • TELEPHONE 266-7261

Application of Trans-Canada Pipe Lines Limited
Under The Gas Resources Preservation Act, 1956

Summary of the Application and the Findings of the Board
(Full Details Appear in OGCB Report 70-B)

Application

TransCanada applied for an amendment of its Permit No. TC 69-9 to increase the volume of gas that may be removed from the Province during the permit term by some 960 billion cubic feet to a total of 22.36 trillion cubic feet. The company also applied to have the volume which may be removed in a 24-hour period increased by 208 million cubic feet to 3.18 billion cubic feet. The additional gas would come in part from reserves developed and under contract to TransCanada in fields now named in the permit, including principally the Alderson, Ferrier and Marten Hills Fields, and in part from six new fields to be added, including the Nipisi and Ricinus West Fields.

Hearing

The application was heard by the Board on March 4, 1970.

Interveners

Representatives of major gas transmission and utility companies intervened for the purposes of cross-examination and argument only. No other parties were represented.

Alberta Gas Reserves

The Board estimates the remaining established reserves of gas at December 31, 1969, to be 45.2 trillion cubic feet or the equivalent of 47.6 trillion cubic feet of 1000 Btu gas. The Board finds that the current rate of growth of initial gas reserves continues to exceed the 10-year average growth rate of 2.6 trillion cubic feet per year.

TransCanada's estimates of reserves and their growth rate were approximately the same as those of the Board.

Cont'd...

Alberta Gas Requirements

The Board estimates the Alberta 30-year requirements for gas to be 16.3 trillion cubic feet of 1000 Btu gas. TransCanada adopted a previous Board estimate of 15.7 trillion cubic feet in its calculations. The Board estimates the contractable Alberta requirements to be 8.8 trillion cubic feet, of which some 1.5 trillion cubic feet are for shrinkage and fuel requirements in Alberta associated with the processing and transportation of gas for removal from the Province. This is the first time the Board has considered the latter requirement separately in determining the contractable requirements.

Gas Surplus to Alberta Requirements

The attached Table E-3, taken from the Board's Report OGCB 70-B, shows the final calculations in the Board's determination of the surplus which would result if TransCanada's application were granted. The table summarizes the requirements to be met and the types of reserves which would be depended upon to meet the requirements.

As indicated in the table, the Board estimates a contractable surplus at December 31, 1969, of 0.9 trillion cubic feet after deducting contractable requirements of 40.0 trillion cubic feet from the contractable reserves of 40.9 trillion cubic feet. The Board estimates a future surplus of 5.1 trillion cubic feet, upon deducting the remaining requirements of 12.8 trillion cubic feet from the remaining and future reserves of 17.9 trillion cubic feet.

TransCanada had determined the contractable and future surpluses to be 1.8 and 6.6 trillion cubic feet respectively.

Disposition of the Application

Having found the quantity of gas applied for to be surplus to the present and future requirements of the Province and the application in other respects also satisfactory, the Board is prepared, with the approval of the Lieutenant Governor in Council, to amend Permit No. TC 69-9 as applied for by the applicant.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AND THE TRANSCANADA APPLICATION AS ESTIMATED BY THE BOARD

AS OF DECEMBER 31, 1969

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES				
NOW CONSIDERED WITHIN ECONOMIC REACH		44.9		
LESS: DEFERRED		4.0		
TOTAL CONTRACTABLE RESERVES			40.9	
CONTRACTABLE REQUIREMENTS				
CONTRACTABLE ALBERTA REQUIREMENTS:				
GENERAL REQUIREMENTS	7.3			
PERMIT-RELATED FUEL AND SHRINKAGE	1.5			
PERMIT REQUIREMENTS: TO MEET REMAINING COMMITMENTS	31.0			
TO MEET TERMINAL YEAR PEAK DAY	0.2			
TOTAL CONTRACTABLE REQUIREMENTS			40.0	
CONTRACTABLE SURPLUS				0.9
REMAINING REQUIREMENTS				
TOTAL ALBERTA REQUIREMENTS FOR DELIVERY 16.3				
LESS: DELIVERIES FROM CONTRACTABLE RESERVES 6.6				
DELIVERIES REQUIRED FROM OTHER SOURCES	9.7			
TOTAL ALBERTA REQUIREMENTS FOR THIRTIETH YEAR PEAK DAY 5.3				
LESS: AVAILABLE FROM CONTRACTABLE RESERVES 2.2				
REQUIRED FROM OTHER SOURCES TO MEET THIRTIETH YEAR PEAK DAY	3.1			
TOTAL REMAINING REQUIREMENTS		12.8		
REMAINING AND FUTURE RESERVES				
FROM DEFERRED GAS AVAILABLE WITHIN 30 YEARS	4.0			
FROM RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH	2.0			
FROM RESERVES PROVIDING FOR TERMINAL YEARS PEAK DAY IN PERMITS	0.2			
FROM GAS NOT YET ESTABLISHED	11.7			
TOTAL REMAINING AND FUTURE RESERVES		17.9		
FUTURE SURPLUS				5.1

REPORT TO
THE LIEUTENANT GOVERNOR IN COUNCIL

IN THE MATTER OF AN APPLICATION OF TRANS-CANADA PIPE LINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

1970

OIL AND GAS CONSERVATION BOARD
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PRICE $ 2.50

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I INTRODUCTION

The subject application, made by Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956, was heard by the Oil and Gas Conservation Board on March 4, 1970, with G. W. Govier, P. Eng. and Vernon Millard sitting.

TransCanada applied to have its Permit No. TC 69-9 amended and the permit and amendments consolidated into a new permit. The proposed amendments, more fully set out in Section II of this report, would increase the permit volumes and add to the list of pools, fields and areas from which gas may be taken for removal from the Province.

Date of Reserve Assessment and Period of Protection

The application contained TransCanada's reserve estimates as of November 24, 1969, which at the hearing were supplemented by the applicant with evidence of some significant developments after that date.

At the hearing the Board stated that, in considering the application, it would estimate the reserves for the Province as of December 31, 1969.

The period for which the Board has assessed the requirements of the Province is 30 years commencing January 1, 1970.

Standard Conditions of Measurement

In this report, unless otherwise stated, volumes of gas are at the standard conditions of 14.65 pounds per square

inch absolute and 60 degrees Fahrenheit.

Where reserves of gas are referred to herein, it means, unless otherwise specified, marketable reserves.

Appearances

The persons listed in Table I appeared at the hearing. All of the interveners, Alberta and Southern, the Utility Companies, Consolidated and Westcoast, intervened for the purposes of cross-examination and argument only.

TABLE I

	Abbreviation of Name Used in Report	Represented by	Witnesses
Trans-Canada Pipe Lines Limited	TransCanada	R. J. Ludgate	G.A. Leslie, P.Geol. P.K. Cole, P.Geol. R.B. Trimble, P.Eng.
Alberta and Southern Gas Co. Ltd.	Alberta and Southern	R.A. MacKimmie, Q.C.	
Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	Utility Companies	G.A.C. Steer, Q.C.	
Consolidated Natural Gas Limited	Consolidated	G.D. Nichols	
Westcoast Transmission Company Limited	Westcoast	S.A. Schmaltz, P.Eng.	
Board Staff		G.J. DeSorcy, P.Eng. N.A. Macleod, Q.C. F. Phillips, P.Eng.	

II SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED

Proposed Permit Amendments

TransCanada applied for the amendment, revision and consolidation of Permit No. TC 69-9 by

(a) increasing the volume of gas that may be removed from the Province in a 24-hour period by 208 million cubic feet to 3,118,000,000 cubic feet,

(b) increasing the volume of gas that may be removed annually by 70 billion cubic feet to 1,002,000,000,000 cubic feet,

(c) increasing the volume of gas that may be removed during the term of the permit by 0.96 trillion cubic feet to 22.36 trillion cubic feet,

(d) adding to clause 3 of the terms and conditions of the consolidated permit reference to Permit No. TC 69-9,

(e) adding to the list of fields, pools and areas from which gas may be removed from the Province the following:

Mikwan South	North Ricinus	Ukalta
Nipisi	Oyen South	Warwick

TransCanada included in its submission a letter in which The Alberta Gas Trunk Line Company Limited stated that it is prepared to construct the facilities necessary to transport the additional volumes applied for.

Reserves

TransCanada estimated the initial marketable reserves available to it in the fields now in its Permit No. TC 69-9 and in the new areas applied for, to be some 23.8 trillion cubic feet of which

97 per cent of the reserves are proved reserves. The reserves comprise some 0.3 trillion cubic feet in new areas and 23.5 trillion cubic feet in fields named in Permit No. TC 69-9.

In assessing total provincial reserves TransCanada did not estimate the reserves of each individual field, pool and area. However, it estimated the reserves of those areas in which significant developments, not reflected in the Board's last estimate, had occurred. On this basis, the applicant estimated that at February 1, 1970, the remaining established reserves of the Province were 45.3 trillion cubic feet of gas, or 47.7 trillion cubic feet on a 1000 British Thermal Units (Btu) per cubic foot equivalent basis.

TransCanada's estimate of the reserves of the Province was obtained by taking the Board's estimate of the reserves of the Province as of May 31, 1969, as modified to November 30, 1969, in OGCB Report 70-A[(1)], and adjusting the estimate to February 1, 1970, for

(a) the growth in reserves in the interim in the fields, pools and areas, the gas from which it has contracted to purchase, and

(b) the growth in other fields and areas where it has observed significant reserve changes, and

(c) the production which has occurred since the earlier estimate.

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(1) In the Matter of an Application ofAlberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. January 1970.

It concluded that adjustments in the reserves of the Province between November 30, 1969 and February 1, 1970 were, in each of categories (a) and (b) an addition of 0.8 trillion cubic feet and in category (c) a reduction of 1.0 trillion cubic feet. The net effect of these changes was therefore, to increase the reserves of the Province by 0.6 trillion cubic feet over the period. TransCanada added that the Board had details of new discoveries and it expected the Board's reserve estimate would reflect such information.

TransCanada submitted that it had reviewed the fields the Board considers beyond economic reach and concluded that the Nipisi Field should now be considered within economic reach. It added that it has some 30 per cent of the gas available at Nipisi committed to it. After adjusting the Board's estimate for these changes it determined that the reserves now beyond economic reach are 2,758 billion cubic feet.

A discussion of individual pool reserve estimates is included in Appendix A.

Reserves under Contract

TransCanada submitted that it had under contract some 96 per cent of the gas it estimated was not committed to others in the fields now in its permits. It added that of the reserves available to it in fields it applied to have added to its permit some 77 per cent are under contract to it, and that a significant portion of the reserves in each of the areas named in the application is under contract to it.

Deliverability

TransCanada submitted deliverability schedules showing that during the term of the permit essentially all of the 22.36 trillion cubic feet, the proposed new total volume of its permit, would be produced from the fields now in the permit and from the new fields it applied to have added to the permit.

Trend in Growth of Reserves

The applicant submitted that the long term trend in the growth of the initial marketable reserves of the Province has been 2.7 trillion cubic feet per year.

The long term growth trend was determined from the initial marketable reserves of the Province at February 1, 1970, which TransCanada determined to be 55.2 trillion cubic feet, and at September 30, 1959, 26.8 trillion cubic feet.

Further discussion of TransCanada's assessment of the trend in the growth of reserves is included in Appendix B.

Alberta Requirements

TransCanada did not present its own forecast of Alberta's 30-year requirements but applied the Board forecast published in OGCB Report 69-F[2] to the period November 24, 1969, to November 23, 1999.

Additional discussion of TransCanada's submission respecting requirements is included in Appendix C.

Surplus

TransCanada submitted that there was an overall surplus of

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(2) In the Matter of an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1969.

9.4 trillion cubic feet of 1000 Btu gas in the Province at February 1, 1970. It submitted that the contractable surplus was 2.8 trillion cubic feet and the future surplus was 6.6 trillion cubic feet, assuming that 11.7 trillion cubic feet of gas from appreciation of established reserves and new discoveries can be relied upon to help meet the future or remaining requirements of the Province.

Details of TransCanada's surplus calculations appear in Appendix D.

III TRUNK LINE AND REPROCESSING PLANTS FUEL, SHRINKAGE AND LOSSES

Following informal discussion with certain permittees, the Board has recently concluded that the procedures by which it has treated the requirements in Alberta for fuel, shrinkage and losses at reprocessing plants and for Trunk Line fuel and losses associated with gas removed from the Province, are not completely satisfactory. These requirements are considered in the calculation of the contractable Alberta surplus. As the result of these discussions the Board, by letters generally of the form included herein as Appendix F, has advised the holders of major permits for the removal of gas from the Province that it will be amending these procedures in dealing with future applications.

In this report, having regard for the intent of the amended procedures outlined in Appendix F, the Board has included specific estimates of the permit-related Alberta requirements rather than general estimates on its previous basis of 30 times the permit-related requirements of the first year of the 30-year period. In addition, to provide for fuller consideration of these requirements in future hearings and reports, it has shown the permit-related requirements separately in Appendices C, D and E. Since the matter was not discussed at the hearing and since it represents a minor change in policy, the Board does not believe it appropriate at this time to require that TransCanada show how the Alberta requirements related to its permit would actually be met. In considering future applications for the removal of gas from the Province, however, the Board will require that the applicant demonstrate that suitable arrangements have been made for the

supply of the fuel, shrinkage and losses associated with the removal from the Province of the gas applied for.

IV FINDINGS

The Board having heard publicly the application under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited, and having studied the evidence submitted by the applicant at the public hearing, and having regard to the advice of its staff and to its own knowledge, finds as follows:

1. THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of marketable gas remaining in the Province at December 31, 1969, to be some 45.2 trillion cubic feet, or the equivalent of 47.6 trillion cubic feet of 1000 Btu gas.

Of the latter total some 2.7 trillion cubic feet are now considered to be beyond economic reach and some 4.0 trillion cubic feet will have production deferred, leaving a contractable reserve of 40.9 trillion cubic feet of 1000 Btu gas.

The present estimate of 47.6 trillion cubic feet is some 0.8 trillion cubic feet more than the Board's estimate at May 31, 1969. The increase is largely due to development drilling and to evaluation of reserves from pool performance where significant pressure and production data have become available.

Details of the Board's estimates and a discussion of the more significant changes since the Board's analysis as at May 31 1969, are presented in Appendix A.

2. THE GROWTH OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The Board policy respecting the future reserves to be used in

the surplus calculation is set forth in the Board report OGCB 69-D[1]. Under the policy the future reserves considered are normally determined by applying the average annual growth rate over the immediately preceding 10-year period to a period of years determined by a formula which has regard for the remaining reserve potential and the reserves already established.

The growth of initial marketable reserves of gas due to new discoveries and to appreciation of previous discoveries has averaged 2.6 trillion cubic feet per year over the past 10 years. This average was determined from the reserve growth of 26.9 trillion cubic feet interpreted by the Board over the 123-month period September 30, 1959 to December 31, 1969.

The formula adopted in Board report OGCB 69-D for determining the number of years of trend gas normally considered in the surplus calculation indicates that at present 4.5 years is appropriate. Since the growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet per year and 3.9 trillion cubic feet per year respectively, and having regard for other relevant factors, the Board estimates the average growth rate of initial gas reserves over the next 4.5 year period as 2.6 trillion cubic feet per year.

The Board under the policy and in the present circumstances therefore recognizes 11.7 trillion cubic feet of future gas reserves in determining the relationship between future reserves and future requirements. Particulars of the determination of these volumes are set forth in Appendix B.

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

3. THE PRESENT AND FUTURE REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates Alberta's requirements for the 30 years, January 1, 1970, to December 31, 1999, to be 16.3 trillion cubic feet of 1,000 Btu gas, with a peak day requirement in the 30th year of 3.6 billion cubic feet. The present estimate represents an increase of 0.3 trillion cubic feet in the total 30-year requirements since the Board's last estimate, which was for the period, June 1, 1969 to May 31, 1999.

The commitments remaining at December 31, 1969, associated with permits issued for removal of gas from the Province, total some 30.3 trillion cubic feet of 1000 Btu gas.

Details of the Board's estimates of Alberta's requirements and permits commitments are presented in Appendic C.

4. THE MEETING OF ALBERTA'S 30-YEAR REQUIREMENTS AND PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 21.6 trillion cubic feet of 1000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the 30-year period, January 1, 1970 to December 31, 1999. Of this total, 16.3 trillion cubic feet are required for actual deliveries and the remaining 5.3 trillion cubic feet are needed to meet the 30th year peak day.

The Board's estimate of 21.6 trillion cubic feet may be considered to consist of 8.8 trillion cubic feet of contractable requirements and 12.8 trillion cubic feet of remaining requirements, the latter being a measure of the reserves needed from sources not now under contract or connected to the Alberta market.

The 8.8 trillion cubic feet of contractable requirements includes 1.5 trillion cubic feet for fuel and shrinkage in Alberta related to gas streams destined to markets outside the Province.

The Board estimates that 30.3 trillion cubic feet of 1000 Btu gas are required to meet the present permit commitments, of which some 0.2 trillion cubic feet represent the reserves needed to ensure deliverability in the terminal year for those permits under which it is contemplated that daily withdrawals for which protection has historically been provided will continue to the end of the permit term.

When the contractable requirement of 8.8 trillion cubic feet and the gas needed to satisfy the permit commitments of 30.3 trillion cubic feet are deducted from the contractable reserve of 40.9 trillion cubic feet, a contractable surplus of 1.8 trillion cubic feet results.

The remaining and future reserves totalling some 17.9 trillion cubic feet consist of 4.0 trillion cubic feet of deferred gas which will be available within the 30-year period, 2.0 trillion cubic feet of gas now beyond economic reach but which the Board believes will be within economic reach and available within 30 years, 0.2 trillion cubic feet of reserves allocated to provide for the peak day in permits which will be available at the termination of the permits and within 30 years, and 11.7 trillion cubic feet representing 4.5 years of growth of gas reserves at the growth rate of 2.6 trillion cubic feet per year. Comparing the total with the 12.8 trillion cubic feet of remaining Alberta requirements results in a surplus of 5.1 trillion cubic feet in the future category. This surplus is

after full provision for the 3.1 trillion cubic feet required from sources not now connected to meet Alberta's 30th year peak day.

Details of the Board's analysis of these matters appear in Appendix D.

5. THE VOLUMES UNDER CONTRACT AND THE PERMIT VOLUMES APPLIED FOR

The Board is satisfied that TransCanada has sufficient reserves available to it and sufficient reserves under contract to warrant granting a permit for the total volume applied for. Furthermore, TransCanada has under contract a sufficient portion of the reserves in each field or area to warrant naming it in the permit.

6. THE APPLICATION FOR REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE APPLICATION WERE GRANTED

The Board interprets the additional volume applied for by TransCanada, 0.96 trillion cubic feet, as consisting of 0.57 trillion cubic feet from fields, pools, and areas named in its present permit and 0.39 trillion cubic feet from new fields, pools and areas. The Board disagrees with TransCanada's estimate of the reserves in some of the new fields and in some of those fields now in its permit. However, the Board finds that its estimate of the reserves in both groups of pools is 0.2 trillion cubic feet greater than the volume applied for.

If the application were granted, the reserves needed to meet the commitment of all permits would increase from the present 30.3 trillion cubic feet of 1000 Btu gas to 31.2 trillion cubic feet. The contractable surplus would be reduced from 1.8 trillion

cubic feet to 0.9 trillion cubic feet. The future surplus of 5.1 trillion cubic feet would remain unchanged.

The Board thus finds that the additional volumes of gas applied for are surplus to the requirements of the Province and the present permit commitments. The Board is satisfied that essentially all of the gas may be produced within a 25-year period although the maximum daily rate requested could not be sustained during the last few years of the term of the permit.

Details of the Board's analysis of these matters is presented in Appendix E.

7. THE WITHDRAWAL RATE

The Board has discussed the amendment to clause 3 of the permit respecting the withdrawal rate, proposed by TransCanada, and has modified the clause somewhat to that in the form of the proposed amended permit included in Appendix G. The amendment simplifies the clause but does not affect its substance.

8. THE DISPOSITION OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

In the light of its findings and its responsibility under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to amend Permit No. TC 69-9 by increasing the volume of gas which TransCanada may remove from the Province by 960 billion cubic feet, by adding the additional

new fields and areas applied for, the permit and amendments to be consolidated in the form shown in Appendix G and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

Vernon Millard
Board Member

DATED at Calgary, Alberta
this 10th day of July, A.D. 1970.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the remaining established reserves of gas in Alberta at December 31, 1969, were 45.2 trillion cubic feet, or the equivalent of 47.6 trillion cubic feet of 1,000 Btu gas. The initial established reserves obtained by adding the cumulative production to December 31, 1969, of 9.7 trillion cubic feet were 54.9 trillion cubic feet. The estimate of remaining established reserves represents an increase on an actual heating value basis of some 0.8 trillion cubic feet since May 31, 1969, the date of the most recent previous Board assessment of the Province's gas reserves. On an actual heating value basis, TransCanada estimated that the remaining established reserves at February 1, 1970, were 45.3 trillion cubic feet. TransCanada submitted reserve estimates for five fields in the "permit applied for" category, and for six other fields where significant increases had occurred since the Board's assessment of May 31, 1969, published in OGCB Reports 69-F[1] and 69-G[2].

While only the established reserves are discussed in this report, the Board has calculated proved and probable reserves of gas. The definitions and interrelationships of these categories of reserves are as follows:

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(1) In the Matter of an Application of Trans-Canada Pipelines Limited under The Gas Resources Preservation Act, 1956. November 1969.

(2) In the Matter of an Application of Consolidated Natural Gas Limited under The Gas Resources Preservation Act, 1956. December 1969.

Proved Reserves are the recoverable gas reserves within the area of a pool completely delineated by drilled wells. A portion of such reserves may be in undrilled drilling spacing units but so located structurally that there is every reasonable probability that the reserves will be produced by wells drilled or to be drilled.

Probable Reserves are the reserves of gas estimated to be recoverable from the pool beyond the proved limits of the pool. The probable pool limits are based on normal geological expectation.

Established Reserves are the reserves of gas whose existence and estimated amount can reasonably be counted upon. They include all of the proved reserves and a judgment portion (usually 50 per cent) of the probable reserves.

In its estimate of reserves, the Board has had regard for the estimates presented by the applicant and interveners at the hearing, the estimates included in various submissions presented recently to the Board, and evaluations made by its staff. The staff has reviewed all estimates submitted by the applicant and the interveners as well as its own previous estimates where desirable because of production history, additional drilling or other new data.

The majority of the increases in the Board's estimates of remaining marketable reserves in the seven-month period ending December 31, 1969, were the result of successful development drilling in various pools, and the majority of the reductions

were due to the production of gas during the period.

A comparison of the Board's reserve estimates of May 31, 1969, and December 31, 1969, follows. Inconsistencies in the summation of the figures result from a rounding of the volumes to the nearest 100 billion cubic feet.

	Actual Basis	1,000 Btu Basis
	(Trillions of Cubic Feet)	
Remaining Established Reserves of Marketable Gas at May 31, 1969	44.3	46.8
Net Additions to Reserves	1.7	1.8
Marketable Gas Produced	0.9	0.9
Remaining Established Reserves of Marketable Gas at December 31,1969	45.2	47.6

Development drilling in the Jumping Pound West Rundle A Pool resulted in an increase of 220 Bcf in the pool reserves, the largest reserve change for any pool in the period from May 31 to December 31, 1969. A discussion of this and other important reserves changes in 1969 appears in OGCB Report 70-18[3], and is not repeated here.

The following table lists some of the large pools for which there are significant differences between the Board's reserve estimate and those of the applicant or other interested parties:

(3) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1969.

Field or Area Pool or Stratum	Reserve Estimates as of December 31,1969 Board Estimate	Other Estimators	Estimates
Alderson Milk River D	150	TransCanada	* 225
Benjamin Creek Rundle A	80	TransCanada	149
Marten Hills Wabiskaw A and Wabamun A	860	TransCanada	* 980
Ricinus West D-3 A	180	Consolidated	375
		TransCanada	196

* Minor adjustments have been made to these estimates so that equivalent reserve areas may be compared.

Alderson Milk River D Pool: The difference between the Board and TransCanada estimates is mainly due to a difference in the estimated reservoir net pay thickness.

Benjamin Creek Rundle A Pool: The TransCanada reserve estimate is based upon a geological interpretation of reservoir volume which is much more optimistic than that of the Board. The Board estimate of 80 Bcf does, in fact, give partial recognition to TransCanada's geological interpretation.

Marten Hills Wabiskaw A and Wabamun A Pools: The difference between the TransCanada and Board estimates for these commingled pools lies mainly in the estimation of reservoir volume, liquid saturation and recovery for the Wabiskaw A Pool.

Ricinus West D-3A Pool: In its assessment of the reserves of this pool, Consolidated has adopted a much larger area assignment than that used by the Board and TransCanada. This accounts

for the principal difference between the estimates.

The Board's estimates of established reserves of gas tabulated by fields and areas are presented in Table A-1. Within each field or area, pools designated by Board orders and having initial marketable reserves of 10 billion cubic feet or greater are shown separately. The reserves of the remaining pools in a field or area are grouped by formation. The table does not show separately fields or areas where the Board's estimate of initial marketable reserves is less than 10 billion cubic feet unless the reserve is supplying a market.

The table includes the Board's estimate of reserves but not detailed reservoir factors for six confidential pools considered at the hearing. These pools are in the Elnora, Obed, Plain, Ricinus West and Ukalta Fields. The sum of the reserves of other confidential pools or zones, and the sum of reserves in non-producing fields or areas having an initial marketable reserve of less than 10 billion cubic feet are shown at the end of the table. These reserves are also included in the Provincial total.

TABLE A-1 - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ACHESON									
VIKING	5	0.75	0.05	4	3	1	1020	1	
BLAIRMORE	13	0.80	0.05	10	1	9	1040	9	
BLAIRMORE ASSOC	19	0.85	0.10	14**					
BLAIRMORE SOLN	7	0.65	0.55	2**	5**	11	1050	12	
D-3 A SOLN	76	0.70	0.55	26	8	18	1070*	19	
ACHESON EAST									
BLAIRMORE	2	0.85	0.10	2		2	1050	2	
BLAIRMORE SOLN	10	0.65	0.45	4		4	1050	4	
ADEN									
BOW ISLAND	5	0.85	0.05	4		4	1000	4	
BASAL COLORADO	7	0.85	0.05	6	2	4	1000	4	
MANNVILLE	1	0.75	0.05	1		1	1020	1	
JURASSIC	2	0.90	0.05	2	1	1	1040	1	
RUNDLE A	34	0.80	0.13	24	8	16	1040	17	
RUNDLE (OTHER)	2	0.90	0.05	2	1	1	1040	1	
ALDERSON									
MILK RIVER D	290	0.55	0.05	150	6	144	960	138	92000
2WS A	500	0.70	0.05	330	17	313	960	300	321500
BOW ISLAND	25	0.80	0.05	20		20	1000	20	
BASAL COLORADO	13	0.85	0.05	10		10	1030	10	
ALEXANDER									
BASAL QUARTZ A	140	0.85	0.03	120	111	9	1060*	10	
MANNVILLE (OTHER)	6	0.40	0.05	2	2	¤ 1	1060*	¤ 1	
ALEXIS									
MANNVILLE	12	0.85	0.05	10		10	1040	10	
BANFF	12	0.85	0.15	9		9	1060	10	
ALIX									
MANNVILLE	10	0.90	0.05	8		8	1090*	9	
D-2 ASSOC	4	0.85	0.35	2		2	1130*	2	
D-2 SOLN	9	0.65	0.65	2		2	1130*	2	
AMBER									
SLAVE POINT	3	0.90	0.15	2		2	1100	2	
SULPHUR POINT	2	0.90	0.20	1		1	1100*	1	
MUSKEG	6	0.90	0.25	4		4	1120*	4	
MUSKEG ASSOC	2	0.85	0.25	2		2	1120*	2	
MUSKEG SOLN	2	0.60	0.25	1		1	1120*	1	
KEG RIVER	7	0.90	0.20	5		5	1200*	6	
KEG RIVER A ASSOC	14	0.90	0.15	11		11	1200*	13	160
KR ASSOC (OTHER)	19	0.90	0.20	14		14	1200*	17	
KEG RIVER SOLN	9	0.70	0.25	5		5	1200*	6	
ANTE CREEK									
PEACE RIVER	11	0.85	0.05	8		8	1100	9	
GETHING 36-67-24	13	0.85	0.05	11		11	1100	12	500
GETHING	13	0.85	0.05	10		10	1100	11	
TRIASSIC	5	0.85	0.05	4		4	1140	5	
ANTELOPE									
VIKING A	13	0.80	0.05	10	1	9	1020	9	4620

¤ MEANS LESS THAN
* MEASURED HIGHER HEATING VALUE

** INCLUDES ASSOCIATED GAS PRODUCTION
*** DEFINITIONS OF COLUMN HEADINGS APPEAR IN APPENDIX 1

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1966 NUL
									1967 NUL
									1967
									1966 NUL
							5080	1950	1966 NUL
									1967
									1968 NUL
									1968 CMG
									1968 CMG
									1966 CMG
									1968 CMG
		GIP BASED ON MATERIAL BALANCE					2860	1961	1969 CMG
									1965 CMG
23	0.21	0.45	440	65	0.94	0.57	960	1941	1969 TCPL AND LOCAL UTILITY
5	0.20	0.40	830	80	0.90	0.58	1970	1956	1967 TCPL
									1964 TCPL
									1965 LOCAL UTILITY
		GIP BASED ON MATERIAL BALANCE					3830	1954	1967 NORTH CANADIAN OILS AND CALGARY POWER
									1961 NORTH CANADIAN OILS AND CALGARY POWER
									1968
									1969
									1962
									1969
									1969
									1968 CONSIDERED BEYOND
									1968 ECONOMIC REACH
									1968
									1968
									1969
									1968
102	0.15	0.15	2240	160	0.84	0.70	5020	1968	1968
									1968
									1969
									1964
35	0.15	0.30	2200	125	0.83	0.62	5670	1961	1967
									1967
									1967
8	0.22	0.50	950	80	0.88	0.59	2360	1957	1967 TCPL

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ANTELOPE (CONTINUED)									
BANFF	12	0.80	0.05	9	6	3	1020	3	
ATHABASCA									
MANNVILLE	6	0.85	0.05	5	2	3	1000	3	
WABAMUN	4	0.90	0.05	3		3	980	3	
ATHABASCA EAST									
MANNVILLE	1	0.80	0.05	1		1	1090	1	
D-1	4	0.60	0.05	2	1	1	1000	1	
ATIM									
VIKING	2	0.80	0.05	1		1	1000	1	
MANNVILLE	2	0.85	0.05	2	1	1	1070*	1	
ATLEE-BUFFALO									
MEDICINE HAT A	59	0.80	0.05	45		45	970	44	69170
VIKING A	61	0.75	0.05	43	13	30	970	29	31910
VIKING B	29	0.75	0.05	21	1	20	970	19	17310
VIKING (OTHER)	7	0.75	0.05	5		5	970	5	
BASAL COLORADO	6	0.80	0.05	5		5	1020	5	
BASAL MANNVILLE A	29	0.80	0.05	22		22	960	21	9550
BASAL MANNVILLE B	17	0.80	0.05	13		13	960	12	4990
MANNVILLE (OTHER)	6	0.85	0.05	5		5	960	5	
BANTRY									
MILK RIVER A	46	0.80	0.05	35	1	34	960	33	18400
2WS	1	0.80	0.05	1		1	970	1	
VIKING	25	0.80	0.05	19		19	970	18	
BASAL COLORADO	3	0.80	0.05	3	1	2	970	2	
MANNVILLE	13	0.85	0.05	10	2	8	1030	8	
MANNVILLE A ASSOC	27	0.85	0.10	21		21	1060*	22	5040
MANN ASSOC (OTHER)	25	0.85	0.05	20		20	1060*	21	
MANNVILLE A SOLN	50	0.70	0.35	23		23	1060*	24	
BAPTISTE									
MANNVILLE	6	0.80	0.05	5		5	970	5	
WABAMUN A	15	0.80	0.05	11		11	980	11	3840
BASHAW									
VIKING	1	0.75	0.05	1		1	970	1	
MANNVILLE	13	0.90	0.05	11		11	1000	11	
MANNVILLE ASSOC	12	0.80	0.05	9		9	1030*	9	
D-3 A ASSOC	16	0.80	0.15	11		11	1100*	12	2740
D-3 ASSOC (OTHER)	2	0.80	0.15	1		1	1100*	1	
BASSANO									
BOW ISLAND	3	0.85	0.05	2		2	1010*	2	
BASAL COLORADO	8	0.80	0.05	6		6	1010*	6	
MANNVILLE C	15	0.85	0.05	12		12	1020*	12	2580
MANNVILLE (OTHER)	3	0.85	0.05	2		2	1020*	2	
BEAVER CROSSING									
MANNVILLE	1	0.70	0.05	1		1	1000	1	
BH LK-FT SASK									
VIKING (MAIN)	610	0.85	0.05	490	151	339	1010	342	
VIKING (OTHER)	37	0.85	0.05	30		30	1010	30	
MANNVILLE	4	0.85	0.05	3		3	1010	3	
BELLIS									
MANNVILLE	13	0.85	0.05	9		9	1015	9	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1967 TCPL	2
										3
										4
									1957 LOCAL UTILITY	5
									1957	6
										7
										8
									1957	9
									1968 LOCAL UTILITY	10
										11
										12
									1957	13
									1963 CIGOL	14
										15
										16
3	0.26	0.40	640	60	0.92	0.57	1610	1960	1969	17
5	0.25	0.50	990	80	0.88	0.60	2600	1949	1967 TCPL	18
4	0.25	0.50	1010	80	0.87	0.60	2320	1954	1967 TCPL	19
									1967	20
										21
									1967	22
7	0.19	0.50	1410	90	0.85	0.59	3220	1953	1967 TCPL	23
8	0.19	0.50	1430	90	0.85	0.59	3290	1954	1967	24
									1968	25
										26
										27
15	0.15	0.35	400	55	0.94	0.57	960	1940	1961 LOCAL UTILITY	28
									1967	29
									1965	30
									1964 CWNG	31
										32
									1961 TCPL	33
5	0.27	0.30	1560	85	0.79	0.73	3210	1948	1969	34
									1968	35
							3250	1948	1969	36
										37
										38
									1968 CONSIDERED BEYOND	39
23	0.15	0.30	510	70	0.93	0.57	1940	1959	1968 ECONOMIC REACH	40
										41
										42
									1963	43
									1966	44
									1966	45
17	0.05	0.15	2330	140	0.85	0.78	5760	1951	1966	46
										47
									1966	48
										49
										50
									1967	51
									1968	52
9	0.20	0.35	1520	100	0.82	0.63	4000	1968	1969	53
									1968	54
										55
										56
									1963 LOCAL UTILITY	57
										58
										59
		GIP BASED ON MATERIAL BALANCE					2590	1946	1966 NUL AND CIGOL	60
									1966	61
									1966	62
										63
										64
									1966	65

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU. FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
BELLIS (CONTINUED)									
NISKU A	43	0.85	0.05	35		35	1000	35	14750
NISKU (OTHER)	1	0.70	0.05	1		1	1000	1	
BELLOY									
SPIRIT RIVER	9	0.80	0.05	7		7	980	7	
GETHING A	34	0.85	0.05	28		28	980	27	10240
GETHING B	31	0.90	0.05	27		27	980	26	6170
DEBOLT A	23	0.90	0.05	20		20	1120	22	1100
BENJAMIN									
RUNDLE A	120	0.80	0.15	80		80	1070	86	2610
RUNDLE B	88	0.80	0.15	60		60	1070	64	2490
BERLAND RIVER									
WABAMUN 23-57-24	18	0.80	0.10	13		13	1020	13	125
WABAMUN 10-58-24	15	0.85	0.10	11		11	1020	11	1100
LEDUC A	440	0.90	0.25	300		300	990	297	1100
LEDUC (OTHER)	3	0.90	0.05	2		2	990	2	
BERLAND RIVER WEST									
WABAMUN 10-58-25	24	0.90	0.30	15		15	1020	15	1100
BERRY									
VIKING	1	0.85	0.05	1		1	1020	1	
MANNVILLE	3	0.85	0.05	3		3	1030	3	
MANNVILLE ASSOC	5	0.85	0.15	4		4	1030	4	
BIG BEND									
WABISKAW 31-68-1	12	0.90	0.05	10		10	990	10	1100
MCMURRAY A	26	0.80	0.05	19		19	990	19	3920
MANNVILLE (OTHER)	34	0.75	0.05	24		24	990	24	
WABAMUN	20	0.80	0.05	15		15	1000	15	
BIGORAY									
PASKAPOO	2	0.60	0.05	1		1	1000	1	
MANNVILLE	18	0.85	0.05	14		14	1080	15	
RUNDLE	20	0.85	0.10	15		15	1080	16	
BIGSTONE									
DUNVEGAN A	53	0.90	0.05	45		45	1140	51	6390
GETHING A	13	0.90	0.05	11		11	1070	12	1100
GETHING (OTHER)	11	0.90	0.05	9		9	1100	10	
WABAMUN	11	0.85	0.40	5		5	1050	5	
D-3 A	390	0.85	0.25	250	12	238	990*	236	7100
BINDLOSS									
VIKING A	400	0.75	0.01	300	127	173	980	170	57050
VIKING B	32	0.70	0.05	21	2	19	980	19	6110
VIKING (OTHER)	6	0.75	0.05	5		5	980	5	
BASAL MANNVILLE A	26	0.90	0.05	23		23	990	23	5310
BANFF	3	0.85	0.05	2		2	1000	2	
BIRCH									
MANNVILLE	7	0.80	0.05	6		6	1000	6	
NISKU	2	0.85	0.05	2		2	990*	2	
CAMROSE	6	0.85	0.05	5		5	990*	5	
BITTERN LAKE									
VIKING	11	0.80	0.05	8		8	1020	8	
GLAUCONITIC A	38	0.85	0.05	30	10	20	1070	21	3530

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
38	0.09	0.20	560	80	0.93	0.57	2100	1965	1966	2
									1966	3
										4
										5
									1961	6
10	0.14	0.40	1280	100	0.87	0.57	3000	1951	1969	7
14	0.14	0.40	1330	110	0.87	0.57	3100	1951	1961	8
39	0.10	0.20	1970	95	0.79	0.63	4700	1951	1961	9
										10
										11
100	0.06	0.25	4150	190	0.94	0.66	11220	1960	1969	12
86	0.05	0.25	3920	185	0.92	0.68	10810	1961	1969	13
										14
										15
417	0.04	0.20	6170	260	1.08	0.71	11850	1968	1969	16
34	0.04	0.20	6390	205	1.09	0.71	11650	1968	1969	17
562	0.08	0.20	5340	250	1.00	0.70	12290	1958	1959	18
									1969	19
										20
										21
71	0.04	0.20	4800	260	0.98	0.70	12320	1958	1959 CONSIDERED BEYOND	22
									ECONOMIC REACH	23
										24
										25
									1969 TCPL	26
									1967 TCPL	27
									1967	28
										29
										30
29	0.20	0.30	800	80	0.86	0.59	2430	1957	1957	31
17	0.20	0.35	900	85	0.88	0.60	2710	1953	1965	32
									1968	33
									1968	34
										35
										36
									1959	37
									1960	38
									1959	39
										40
										41
16	0.15	0.45	2600	145	0.79	0.69	6440	1959	1966	42
20	0.14	0.30	2500	215	0.89	0.66	7780	1960	1961	43
									1961	44
									1964	45
										46
105	0.07	0.15	4800	240	0.97	0.69	11080	1960	1964 TCPL	47
										48
										49
14	0.29	0.45	990	80	0.88	0.59	2260	1952	1969 TCPL	50
10	0.29	0.45	1000	80	0.88	0.59	2530	1957	1967 TCPL	51
									1967	52
7	0.23	0.40	1460	85	0.85	0.59	2770	1954	1967	53
										54
									1967	55
										56
										57
									1962	58
									1962	59
									1969	60
										61
										62
									1967	63
17	0.25	0.40	1310	115	0.86	0.64	4010	1956	1967 CIGOL, PLAINS WEST-	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BITTERN LAKE (CONTINUED)									
GLAUCONITIC B	21	0.85	0.05	17	3	14	1070	15	1210
ELLERSLIE A	14	0.85	0.05	12		12	1070	13	2370
MANNVILLE (OTHER)	44	0.85	0.05	35	1	34	1070	36	
BLACK									
SLAVE POINT	18	0.90	0.15	13		13	1100	14	
SULPHUR POINT ASSOC	1	0.85	0.15	1		1	1100	1	
MUSKEG	1	0.85	0.10	1		1	1100	1	
KEG RIVER	5	0.85	0.15	3		3	1150	3	
KEG RIVER ASSOC	4	0.85	0.15	3		3	1200	4	
BLACK BUTTE									
2WS	2	0.80	0.05	2		2	960	2	
BOW ISLAND	9	0.85	0.05	7	3	4	980	4	
BASAL COLORADO A	15	0.85	0.05	12	4	8	1000	8	2840
BSL COLORADO (OTHER)	10	0.85	0.05	8	5	3	1000	3	
MANNVILLE (OTHER)	7	0.85	0.05	5		5	1030	5	
SUNBURST-SWIFT A	18	0.90	0.05	15	9	6	1000	6	2040
SAWTOOTH A	28	0.80	0.05	21	18	3	1000	3	
RUNDLE A	16	0.80	0.05	12	5	7	1020	7	2750
BLACK DIAMOND									
RUNDLE A	24	0.85	0.15	17		17	1100	19	500
BLUERIDGE									
MANNVILLE	3	0.80	0.05	2		2	1100	2	
JURASSIC A	14	0.90	0.05	12		12	1100	13	500
JURASSIC (OTHER)	8	0.80	0.10	5		5	1100	6	
RUNDLE	2	0.75	0.05	2		2	1130	2	
RUNDLE ASSOC	7	0.80	0.10	5		5	1130	6	
BOLLOQUE LAKE									
VIKING	2	0.80	0.05	1		1	1060	1	
MANNVILLE	14	0.80	0.05	10		10	990	10	
BONNIE GLEN									
CARDIUM SOLN	6	0.65	0.10	3		3	1040*	3	
VIKING	2	0.85	0.10	1		1	1050	1	
MANNVILLE	5	0.85	0.10	4	3	1	1100*.	1	
WABAMUN	1	0.85	0.10	1		1	1100*	1	
WINTERBURN	1	0.85	0.10	1		1	1100*	1	
D-3	14	0.70	0.15	9	7	2	1100*	2	
D-3 A ASSOC	430	0.85	0.15	310		310	1220*	378	2990
D-3 A SOLN	540	0.70	0.25	280	60	220	1220*	268	
BONNYVILLE									
MANNVILLE	4	0.80	0.05	3	3	□ 1	980	□ 1	
MANNVILLE ASSOC	1	0.80	0.05	1		1	980	1	
BOUNDARY LAKE SOUTH									
CADOMIN	11	0.80	0.10	8		8	1060	8	
TRIASSIC	3	0.80	0.05	2		2	1050	2	
KISKATINAW D	37	0.85	0.05	29	12	17	1080	18	
KISKATINAW E	19	0.85	0.10	15	1	14	1080	15	1100
KISKATINAW (OTHER)	9	0.85	0.05	7	3	4	1080	4	
GOLATA A	13	0.85	0.05	11	8	3	1080	3	1000

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
29	0.24	0.40	1370	115	0.85	0.64	4180	1947	1967 ERN GAS & ELEC AND	2
									NUL	3
										4
11	0.19	0.35	1350	115	0.83	0.68	4140	1952	1967	5
									1967 CIGOL	6
										7
										8
									1967 CONSIDERED BEYOND	9
							...		1967 ECONOMIC REACH	10
									1967	11
									1967	12
										13
									1967	14
										15
										16
									1961 CMG	17
									1969 CMG	18
15	0.20	0.40	930	80	0.89	0.58	2540	1944	1968 CMG	19
									1968 CMG	20
										21
									1963 CMG	22
19	0.20	0.30	1030	85	0.87	0.57	2960	1944	1963 CMG	23
		GIP BASED ON MATERIAL BALANCE					3200	1944	1967 CMG	24
18	0.10	0.20	1200	90	0.87	0.58	3280	1944	1968 CMG	25
										26
										27
59	0.10	0.15	3630	195	0.87	0.74	9020	1967	1967	28
										29
										30
									1964	31
26	0.28	0.30	1800	150	0.85	0.66	5500	1957	1966	32
									1968	33
									1968	34
										35
									1969	36
										37
										38
									1966	39
									1967	40
										41
										42
									1969	43
									1963	44
									1964 NUL	45
									1967	46
										47
									1967	48
									1967 NUL	49
216	0.09	0.10	2440	140	0.79	0.70	6700	1952	1966	50
							7000	1952	1966 NUL	51
										52
										53
									1964 LOCAL UTILITY	54
									1963	55
										56
										57
									1964	58
									1968	59
		GIP BASED ON MATERIAL BALANCE					6210	1964	1969 WESTCOAST	60
22	0.13	0.10	2360	145	0.86	0.60	6130	1965	1969 WESTCOAST	61
										62
									1966 WESTCOAST	63
17	0.14	0.20	2370	145	0.86	0.59	6100	1958	1969 WESTCOAST	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BOUNDARY LAKE SOUTH (CONTINUED)									
GOLATA B	16	0.85	0.05	13	8	5	1080	5	1000
BOW ISLAND									
BOW ISLAND	48	0.90	0.05	40	12	28	1030	29	
BOYLE									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
NISKU	8	0.85	0.05	6		6	990	6	
BRAEBURN									
CADOMIN	4	0.80	0.05	3	1	2	1060*	2	
BALDONNEL A	29	0.80	0.10	21	5	16	1090*	17	4890
BELLOY A	55	0.80	0.05	42	3	39	1030*	40	3560
BRAZEAU RIVER									
ELKTON A	670	0.80	0.10	480	6	474	1050*	498	41180
ELKTON-SHUNDA A	270	0.80	0.10	190		190	1040*	198	16230
SHUNDA A	110	0.75	0.10	74	11	63	1080*	68	24370
BROOKS									
MILK RIVER	9	0.80	0.05	7	4	3	990	3	
BROWN CREEK									
RUNDLE 20-44-17	59	0.80	0.15	40		40	970	39	2000
BRUCE									
VIKING	25	0.80	0.05	19		19	1000	19	
MANNVILLE	9	0.80	0.05	7		7	1020	7	
BURNT TIMBER									
RUNDLE A	370	0.85	0.20	250		250	1030	258	12160
CALAIS									
GETHING	14	0.85	0.05	11		11	1000	11	
CADOMIN	12	0.85	0.05	10		10	1000	10	
CALLING LAKE									
MANNVILLE	2	0.85	0.05	2		2	1000	2	
D-2	49	0.75	0.05	35	2	33	1000	33	
CAMPBELL-NAMAO									
BLAIRMORE	4	0.85	0.05	3		3	1020	3	
BLAIRMORE E ASSOC	31	0.80	0.05	23**					1740
BLAIR ASSOC (OTHER)	13	0.80	0.05	10**					
BLAIRMORE SOLN	8	0.60	0.05	4**	21**	16	1020*	16	
CARBON									
BASAL COLORADO	4	0.85	0.05	3		3	1020	3	
GLAUCONITIC	160	0.85	0.05	130	33	97	1120	109	11800
MANNVILLE (OTHER)	4	0.85	0.05	3		3	1100	3	
RUNDLE	4	0.85	0.05	3		3	1110	3	
CAROLINE									
VIKING	2	0.80	0.05	1		1	1040*	1	
VIKING A ASSOC	160	0.80	0.05	120	8	112	1040*	116	40600
BASAL MANNVILLE B	15	0.85	0.10	12	2	10	1070	11	500
BASAL MANNVILLE C	16	0.85	0.10	12		12	1070	13	500
MANNVILLE (OTHER)	17	0.85	0.05	13		13	1040*	14	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
20	0.14	0.20	2370	145	0.86	0.59	6100	1964	1969 WESTCOAST
		RESERVE BASED ON PRODUCTION & INJECTION DATA					1920	1909	1953 CWNG STORAGE RESERVOIR
									1966
									1966
									1966 WESTCOAST
8	0.16	0.30	2150	145	0.86	0.61	5680	1954	1968 WESTCOAST
35	0.11	0.50	2970	180	0.90	0.58	7280	1954	1968 WESTCOAST
17	0.11	0.10	3860	215	0.94	0.64	10150	1959	1969 A&S AND TCPL
22	0.11	0.30	3870	335	0.95	0.68	9870	1965	1969 TCPL
9	0.08	0.30	3910	205	0.94	0.65	10200	1965	1968 A&S AND TCPL
									1961 LOCAL UTILITY
89	0.04	0.20	4550	115	0.98	0.64	10840	1960	1964 CONSIDERED BEYOND ECONOMIC REACH
									1967
									1967
83	0.06	0.15	3800	205	0.91	0.72	10900	1959	1966
									1960 LOCAL UTILITY
									1964
									1967 GREAT CANADIAN OIL SANDS LIMITED
									1967 GREAT CANADIAN OIL SANDS LIMITED
									1964
30	0.19	0.20	1220	115	0.85	0.67	3620	1951	1969
									1969
									1964 CIGOL
									1964
22	0.20	0.35	1480	120	0.83	0.68	4750	1955	1966 CWNG
									1964
									1965
									1967
7	0.11	0.25	2500	165	0.83	0.67	8070	1957	1967 TCPL
26	0.15	0.30	4260	185	0.92	0.78	9460	1958	1964 A&S
27	0.15	0.30	4040	180	0.89	0.78	8900	1964	1965
									1965 TCPL

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
*** 1	2	3	4	5	6	7	8	9	10
CAROLINE (CONTINUED)									
RUNDLE	13	0.85	0.15	10		10	1020*	10	
CARSON CREEK									
BEAVERHILL LAKE A	210	0.85	0.15	150	11	139	1080*	150	20390
BEAVERHILL LAKE B	110	0.85	0.15	80	-14	94	1080*	102	6980
CARSON CREEK NORTH									
BH LK A ASSOC	26	0.85	0.15	19		19	1100*	21	2880
BH LK A SOLN	110	0.45	0.20	38	5	33	1100*	36	
BH LK ASSOC (OTHER)	7	0.85	0.15	5		5	1100*	6	
BH LK B SOLN	360	0.40	0.20	110	11	99	1100*	109	
CARSTAIRS									
BLAIRMORE	16	0.85	0.15	11		11	1100	12	
ELKTON A	1140	0.90	0.15	870	277	593	1070*	635	
RUNDLE ASSOC	6	0.85	0.15	5		5	1070*	5	
CASTOR									
VIKING A	33	0.80	0.05	25		25	1040	26	20320
MANNVILLE A	16	0.80	0.05	12	1	11	1090	12	5300
MANNVILLE (OTHER)	2	0.85	0.05	2		2	1090	2	
CESSFORD									
VIKING H	16	0.75	0.03	11		11	1020*	11	6460
VIKING I	14	0.75	0.03	10		10	1020*	10	1100
VIKING (OTHER)	78	0.65	0.03	49	11	38	1060*	40	
BASAL COLORADO E	120	0.80	0.04	90	45	45	1030*	46	24430
BSL COLORADO (OTHER)	55	0.65	0.04	34	3	31	1030*	32	
BSL COLORADO A ASSOC	890	0.85	0.04	730**					135000
BSL COLORADO A SOLN	20	0.65	0.21	10**	358**	382	1030*	393	
GLAUCONITIC A	19	0.75	0.05	13		13	1080*	14	8410
GLAUCONITIC B	15	0.75	0.05	11	1	10	1080*	11	5810
MANNVILLE F	23	0.85	0.04	19	3	16	1000*	16	3670
MANNVILLE G	40	0.85	0.04	33	22	11	1000*	11	5760
MANNVILLE H	71	0.85	0.04	58	26	32	1000*	32	7010
MANNVILLE I	22	0.75	0.04	16	6	10	1000*	10	5470
MANNVILLE J	32	0.85	0.04	26	15	11	1000*	11	4870
MANNVILLE K	17	0.75	0.04	12	1	11	1000*	11	3300
MANNVILLE V	27	0.20	0.04	20	12	8	1000*	8	
MANNVILLE (OTHER)	67	0.85	0.04	53	20	33	1000*	33	
MANNVILLE C ASSOC	19	0.85	0.04	16**					3930
MANNVILLE C SOLN	12	0.65	0.17	7**	5**	18	1030*	19	
MANN ASSOC (OTHER)	2	0.85	0.04	1	4	3	1030*	2	
CHAMBERS									
MANNVILLE	6	0.85	0.10	4		4	1030	4	
RUNDLE	13	0.85	0.15	9		9	1080	10	
CHARLOTTE LAKE									
MANNVILLE	3	0.75	0.05	2		2	1000	2	
CHERHILL									
VIKING	6	0.80	0.05	4		4	1060	4	
MANNVILLE	14	0.85	0.05	11		11	1040	11	
BANFF	4	0.85	0.05	3		3	1060	3	
BANFF ASSOC	9	0.85	0.10	7		7	1060	7	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1965 A&S
17	0.08	0.20	3790	200	0.85	0.97	8550	1961	1964 POOLS BEING CYCLED
24	0.08	0.20	3790	200	0.85	0.97	8610	1957	1964 AND GAS SOLD TO NUL
									AND A&S
10	0.09	0.90	3740	185	0.84	0.79	8580	1958	1969
							8630	1958	1965 INJ INTO CARSON CRK
							8700	1958	1969
							8740	1958	1969 INJ INTO CARSON CRK
									1967
		GIP BASED ON MATERIAL BALANCE					8100	1958	1967 TCPL
									1967
6	0.21	0.55	860	90	0.89	0.61	3160	1949	1969 TCPL
6	0.20	0.65	1130	90	0.85	0.63	3500	1949	1969 LOCAL UTILITY
									1969
6	0.21	0.45	1110	75	0.86	0.59	2630	1953	1968 TCPL
15	0.21	0.45	1100	80	0.86	0.59	2730	1953	1968
									1968 TCPL
8	0.24	0.40	1260	85	0.84	0.61	2970	1950	1968 TCPL
									1968 TCPL
10	0.27	0.40	1260	80	0.84	0.61	2860	1950	1968
							2870	1950	1968 TCPL
6	0.17	0.50	1370	100	0.82	0.65	3850	1960	1968 TCPL
6	0.17	0.50	1370	95	0.82	0.65	3570	1962	1968 TCPL
10	0.24	0.45	1420	90	0.81	0.65	3290	1951	1968 TCPL
13	0.21	0.50	1420	90	0.81	0.65	3390	1950	1968 TCPL
14	0.25	0.45	1440	85	0.80	0.65	3070	1954	1968 TCPL
7	0.27	0.50	1420	90	0.81	0.65	3340	1951	1968 TCPL
10	0.23	0.45	1540	90	0.80	0.65	3400	1958	1968 TCPL
8	0.27	0.50	1420	90	0.81	0.65	3255	1952	1968 TCPL
		GIP BASED ON MATERIAL BALANCE					3800	1959	1969 TCPL
									1968 TCPL
6	0.24	0.35	1400	90	0.81	0.65	3320	1951	1968
									1968 TCPL
									1968 TCPL
									1967
									1967
									1967 CANADIAN FORCES BASE
									AT COLD LAKE
									1968
									1968
									1968
									1968

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
*** 1	2	3	4	5	6	7	8	9	10
CHESTERMERE									
RUNDLE A	27	0.85	0.15	20		20	1100	22	1100
CHIGWELL									
MANNVILLE A	46	0.85	0.10	35	14	21	1110	23	
MANNVILLE (OTHER)	13	0.75	0.10	9	1	8	1110	9	
CHINOOK RIDGE									
CADOTTE 12-65-13	32	0.80	0.10	23		23	1020	23	1100
PEACE RIVER (OTHER)	13	0.80	0.10	9		9	1020	9	
SPIRIT R 12-65-13	20	0.80	0.10	15		15	1020	15	500
CLIVE									
VIKING	4	0.80	0.05	3		3	990	3	
MANNVILLE	5	0.85	0.05	4		4	1020	4	
D-2 A ASSOC	39	0.85	0.30	23		23	1050*	24	4240
D-2 ASSOC (OTHER)	1	0.85	0.30	1		1	1050*	1	
D-2 SOLN	38	0.40	0.55	7		7	1050*	7	
D-3 A ASSOC	33	0.75	0.30	18		18	1050*	19	3950
D-3 A SOLN	70	0.40	0.60	11		11	1050*	12	
COLD LAKE									
MANNVILLE	8	0.70	0.05	6	4	2	1000	2	
COMREY									
2WS	5	0.80	0.05	4		4	940	4	
BOW ISLAND	34	0.75	0.05	24	17	7	940	7	6980
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	940	1	
UPPER MANNVILLE A	16	0.90	0.05	14		14	1000	14	1100
JURASSIC	1	0.80	0.05	1		1	1000	1	
CONNORSVILLE									
VIKING	8	0.80	0.05	6	3	3	1000	3	
LOWER MANNVILLE A	52	0.85	0.05	42	4	38	1100	42	10110
MANNVILLE (OTHER)	10	0.85	0.05	8	2	6	1100	7	
COUNTESS									
BOW ISLAND A	34	0.80	0.05	26	5	21	1010*	21	14490
BOW ISLAND C	17	0.80	0.05	13	1	12	1010*	12	6080
BOW ISLAND F	15	0.85	0.05	12		12	1010*	12	2230
BOW ISLAND (OTHER)	27	0.80	0.05	20	1	19	1010*	19	
BASAL COLORADO A	170	0.85	0.05	140	81	59	1010*	60	
BSL COLORADO (OTHER)	5	0.90	0.05	5		5	1010*	5	
MANNVILLE	49	0.85	0.05	39	6	33	1020*	34	
BASAL QUARTZ B ASSOC	12	0.85	0.05	10		10	1020*	10	1370
MANN ASSOC (OTHER)	5	0.85	0.05	4		4	1020*	4	
MISS ASSOC	3	0.80	0.10	2		2	1030*	2	
CRAIGEND									
PELICAN	3	0.75	0.05	2		2	1000	2	
GRAND RAPIDS C	18	0.65	0.05	11		11	1000	11	12150
GRAND RAPIDS F	19	0.65	0.05	12		12	1000	12	10120
MANNVILLE (OTHER)	66	0.75	0.05	46		46	1000	46	
MANNVILLE ASSOC	1	0.75	0.05	1		1	1000	1	
GROSMONT A	200	0.75	0.05	140	2	138	1000	138	87050
CRAIG LAKE									
VIKING	1	0.75	0.05	1		1	1000	1	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
42	0.10	0.15	2790	155	0.80	0.76	6820	1968	1969
		GIP BASED ON MATERIAL BALANCE					5160	1952	1968 TCPL
									1968 TCPL
23	0.20	0.30	3300	230	0.85	0.80	9200	1956	1961 CONSIDERED BEYOND
									1961 ECONOMIC REACH
32	0.20	0.30	3400	235	0.86	0.80	9460	1956	1961
									1966
									1966
20	0.06	0.15	2480	150	0.73	0.75	6040	1951	1967
									1968
									1968
20	0.06	0.15	2550	150	0.73	0.81	6140	1952	1967
							6150	1952	1968
									1966 LOCAL UTILITY
									1960
16	0.25	0.50	770	80	0.92	0.59	2480	1952	1968 CMG
									1960
33	0.21	0.35	990	80	0.88	0.57	2750	1968	1968 CMG
									1960
									1964 TCPL
11	0.16	0.35	1410	105	0.85	0.61	3650	1956	1965 TCPL
									1965 TCPL
6	0.23	0.50	1040	85	0.87	0.60	2890	1951	1968 TCPL
7	0.22	0.50	1040	85	0.87	0.60	2860	1955	1968 TCPL
13	0.27	0.50	1170	85	0.86	0.60	2830	1967	1968
									1968 TCPL
		GIP BASED ON MATERIAL BALANCE					3500	1951	1968 TCPL
									1968
									1964 TCPL
13	0.21	0.30	1470	110	0.82	0.67	4280	1958	1964
									1968
									1961
									1967
8	0.31	0.50	380	80	0.95	0.57	1200	1966	1969
10	0.35	0.50	380	80	0.95	0.57	1230	1966	1969
									1969
									1969
31	0.11	0.55	410	75	0.94	0.57	1660	1949	1969 TCPL
									1968 LOCAL UTILITY

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
CROSSFIELD									
BELLY RIVER	2	0.75	0.05	2		2	1000*	2	
CARDIUM SOLN	74	0.30	0.45	12	1	11	1140*	13	
BASAL QUARTZ A	81	0.85	0.10	62	2	60	1020*	61	12160
BLAIRMORE (OTHER)	36	0.85	0.10	28	2	26	1020*	27	
RUNDLE A	1240	0.90	0.10	1000	208	792	1070*	847	
RUNDLE B	900	0.85	0.15	650	233	417	1070*	446	21220
RUNDLE D	13	0.85	0.10	10		10	1020*	10	500
WABAMUN A	2080	0.85	0.50	890	121	769	980	754	102680
CROSSFIELD EAST									
BLAIRMORE	6	0.85	0.10	5		5	1020*	5	
ELKTON A	150	0.90	0.12	120	41	79	1140*	90	
ELKTON C	32	0.85	0.10	24		24	1140*	27	1100
WABAMUN A	1590	0.85	0.55	610	32	578	970	561	55510
DIXONVILLE									
MANNVILLE	9	0.85	0.05	7		7	980	7	
TRIASSIC	8	0.90	0.05	7		7	1030	7	
LEDUC	4	0.85	0.05	3		3	1070	3	
DONALDA									
VIKING B	25	0.80	0.05	19		19	970	18	9390
VIKING C	17	0.80	0.05	13		13	970	13	7170
VIKING (OTHER)	17	0.75	0.05	13		13	970	13	
MANNVILLE	11	0.85	0.05	9		9	980	9	
DOWLING LAKE									
MANNVILLE	5	0.80	0.05	3	2	1	1030*	1	
DRUMHELLER									
VIKING	3	0.85	0.05	2		2	1080	2	
MANNVILLE H	16	0.85	0.10	12	2	10	1080	11	2360
MANNVILLE (OTHER)	27	0.85	0.05	22		22	1080	24	
MANNVILLE F ASSOC	27	0.85	0.05	21	2	19	1080	21	37440
MANN ASSOC (OTHER)	12	0.80	0.05	9		9	1080	10	
BANFF	3	0.80	0.10	2		2	1080	2	
DUHAMEL									
VIKING	4	0.90	0.05	4		4	1000	4	
MANNVILLE	5	0.85	0.05	4		4	1030	4	
D-2 ASSOC	2	0.90	0.10	2	1	1	1100	1	
D-3 SOLN	6	0.50	0.55	1	1	□ 1	1100	□ 1	
DUNVEGAN									
CADOTTE	9	0.75	0.05	7		7	1010	7	
DEBOLT	3	0.90	0.05	3		3	1040	3	
DUVERNAY									
VIKING	4	0.80	0.05	3	2	1	1000*	1	
DYBERG									
BELLY RIVER	3	0.80	0.05	2		2	950	2	
VIKING	8	0.90	0.05	7		7	1000	7	
BSL QTZ 15-44-23	12	0.90	0.05	10		10	1020	10	1200
EAGLESHAM									
BLUESKY	5	0.85	0.05	4		4	1000	4	
CADOMIN ASSOC	7	0.85	0.05	5		5	1060	5	
DEBOLT A	17	0.85	0.05	14		14	1110	16	2040
DEBOLT B	19	0.85	0.05	15		15	1110	17	1100

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1969
									1966 TCPL
9	0.11	0.30	2890	150	0.82	0.70	7330	1957	1966 WESTCOAST AND TCPL
									1966 TCPL
		GIP BASED ON MATERIAL BALANCE					8410	1956	1969 A&S AND TCPL
71	0.08	0.15	3040	165	0.88	0.70	7440	1957	1967 WESTCOAST AND TCPL
44	0.08	0.20	3310	180	0.88	0.71	8200	1951	1964
34	0.06	0.15	3630	165	0.71	0.90	8500	1954	1967 WESTCOAST AND TCPL
									1968
		GIP BASED ON MATERIAL BALANCE					7490	1960	1968 TCPL
48	0.09	0.20	2780	170	0.82	0.74	7590	1967	1968
51	0.05	0.20	3630	180	0.72	0.91	9000	1960	1968 TCPL
									1962 CONSIDERED BEYOND
									1962 ECONOMIC REACH
									1962
6	0.23	0.35	920	100	0.90	0.60	3280	1960	1969 CONSIDERED BEYOND
6	0.23	0.35	905	100	0.90	0.60	3420	1957	1969 ECONOMIC REACH
									1969
									1969
									1960 LOCAL UTILITY
									1967
15	0.16	0.45	1450	125	0.84	0.66	4370	1961	1968 TCPL
									1966
9	0.20	0.25	1430	120	0.82	0.68	4220	1950	1968 TCPL
									1966
									1963 TCPL
									1965 INJECTED INTO D-3
									1965 INJECTED INTO D-3
									1957 INJECTED INTO D-3
									1966 INJECTED
									1963 CONSIDERED BEYOND
									1963 ECONOMIC REACH
									1961 WESTERN MINERALS AND LOCAL UTILITY
									1960 CONSIDERED BEYOND
									1960 ECONOMIC REACH
17	0.18	0.30	1480	130	0.84	0.62	4620	1954	1960
									1965
									1965
11	0.18	0.25	1870	135	0.85	0.64	4480	1952	1966
17	0.20	0.20	1980	125	0.83	0.64	4700	1959	1965

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
EAGLESHAM (CONTINUED)									
DEBOLT C	26	0.85	0.05	21		21	1110	23	1100
EDSON									
GETHING A	210	0.85	0.10	160		160	1050	168	11450
ELKTON A	2350	0.90	0.10	1900	244	1656	1030*	1706	121800
ELKTON 26-51-19	22	0.85	0.10	17		17	1030*	18	1100
RUNDLE (OTHER)	19	0.80	0.10	13		13	1030*	13	
EDWAND									
MANNVILLE	4	0.80	0.05	3		3	1000	3	
ELK POINT									
MANNVILLE	3	0.80	0.05	2	1	1	990*	1	
ELLERSLIE									
BLAIRMORE ASSOC	2	0.75	0.15	1		1	1000	1	
ELNORA									
UPPER MANNVILLE A	16	0.75	0.05	12		12	1100	13	
LOWER MANNVILLE A	25	0.75	0.05	18		18	1100	20	
MANNVILLE (OTHER)	3	0.80	0.05	2		2	1100	2	
ENCHANT									
MILK RIVER	5	0.75	0.05	3	1	2	1000*	2	
BOW ISLAND A	15	0.75	0.05	11		11	1000*	11	28780
BOW ISLAND (OTHER)	16	0.85	0.05	12	4	8	1000*	8	
BASAL COLORADO	1	0.75	0.05	1		1	1000*	1	
UPPER MANNVILLE A	13	0.85	0.05	11	3	8	1000*	8	4010
MANNVILLE (OTHER)	11	0.85	0.10	8		8	1000*	8	
JURASSIC	2	0.75	0.10	2		2	1000*	2	
RUNDLE	5	0.85	0.10	4	2	2	1000*	2	
EQUITY									
MANNVILLE	4	0.80	0.05	3		3	1130*	3	
LOWER MANN A & PEK A	46	0.85	0.10	33	3	30	1130*	34	8720
ERSKINE									
VIKING	4	0.80	0.05	3		3	1040	3	
BLAIRMORE	21	0.80	0.10	15	4	11	1090	12	
D-2 SOLN	1	0.65	0.35	1		1	1100	1	
D-3	1	0.85	0.20	1		1	1070	1	
D-3 A ASSOC	34	0.90	0.20	25		25	1070	27	2760
D-3 SOLN	19	0.50	0.75	2		2	1110	2	
ESTHER									
BELLY RIVER A	21	0.75	0.05	15		15	990	15	31050
BANFF A	21	0.85	0.05	17	4	13	1000	13	1600
ETHEL LAKE									
MANNVILLE	3	0.80	0.05	2		2	1000	2	
ETZIKOM									
BOW ISLAND A	68	0.75	0.05	48	35	13	930	12	
MANNVILLE	2	0.75	0.05	1		1	1010	1	
EXCELSIOR									
VIKING	8	0.80	0.05	7	3	4	1000	4	
MANNVILLE A ASSOC	38	0.90	0.05	33		33	970	32	3270

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
23	0.20	0.20	2000	125	0.81	0.65	4700	1959	1965
27	0.10	0.25	3360	180	0.88	0.68	8400	1963	1969 TCPL
22	0.10	0.10	3880	225	0.94	0.63	9380	1962	1969 TCPL
31	0.08	0.10	3990	210	0.94	0.63	10120	1964	1966
									1966 TCPL
									1966 LOCAL UTILITY
									1964 LOCAL UTILITY
									1966 EDMONTON LIQUID GAS
		CONFIDENTIAL							1969
		CONFIDENTIAL							1969
									1953
									1964 TCPL
2	0.15	0.30	950	80	0.89	0.59	2470	1960	1967 TCPL
									1967 TCPL
									1962
5	0.20	0.35	1580	90	0.81	0.66	3300	1953	1968 TCPL
									1961 TCPL
									1961
									1966 TCPL
									1968 TCPL
21	0.08	0.35	1620	125	0.83	0.67	5420	1962	1967 TCPL
									1962
									1966 TCPL
									1969
									1968
31	0.06	0.20	2210	145	0.71	0.70	5350	1953	1969
							5390	1953	1966
3	0.31	0.35	330	55	0.95	0.58	800	1956	1964
26	0.19	0.30	1180	85	0.87	0.59	2770	1965	1966 TCPL
									1967 LOCAL EXPERIMENTAL PROJECT
		GIP BASED ON MATERIAL BALANCE					2230	1951	1967 SOUTH ALBERTA PIPE LINES
									1961
									1953 CIGOL AND PLAINS-WESTERN GAS & ELEC
24	0.20	0.35	1140	80	0.87	0.63	3450	1953	1953

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU.FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
EYREMORE									
BOW ISLAND	15	0.70	0.05	10		10	960	10	
FAIRYDELL-BON ACCORD									
VIKING A	110	0.80	0.05	88	39	49	1020	50	
VIKING (OTHER)	9	0.80	0.05	7	1	6	1020	6	
MANNVILLE	15	0.80	0.05	12	3	9	990	9	
BASAL MANN C ASSOC	17	0.80	0.10	12		12	990	12	1430
MANN ASSOC (OTHER)	2	0.80	0.10	2		2	990	2	
FENN-BIG VALLEY									
VIKING	19	0.80	0.90	2	1	1	1000*	1	
D-2 A SOLN	150	0.65	0.85	15	8	7	1110*	8	
D-3 SOLN	9	0.60	0.85	1		1	1110*	1	
FERRIER									
BELLY RIVER SOLN	4	0.65	0.40	2		2	960	2	
CARDIUM	18	0.85	0.10	14		14	1000	14	
CARDIUM D ASSOC	110	0.85	0.10	82		82	1000	82	8540
CARDIUM D SOLN	100	0.65	0.20	54		54	1000	54	
CARDIUM E ASSOC	410	0.85	0.10	310		310	1000	310	12680
CARDIUM E SOLN	190	0.65	0.20	99		99	1000	99	
CARDIUM SOLN (OTHER)	6	0.65	0.25	3		3	1000	3	
VIKING A SOLN	31	0.65	0.25	15	4	11	1130	12	
RUNDLE	2	0.80	0.10	2		2	1100	2	
BANFF	8	0.85	0.10	6		6	1100	7	
FIGURE LAKE									
VIKING	4	0.75	0.05	3		3	960	3	
MANNVILLE	13	0.80	0.05	10		10	1000	10	
D-2 B	13	0.85	0.05	11		11	1000	11	6700
D-2 (OTHER)	12	0.85	0.05	8		8	1000	8	
FLAT									
MANNVILLE	13	0.80	0.05	10		10	1020	10	
WABAMUN A	156	0.80	0.05	119		119	1040	124	32650
FOREMOST									
BOW ISLAND	31	0.85	0.05	27	8	19	950	18	10400
FORT KENT									
MANNVILLE	6	0.75	0.05	4	2	2	980	2	
FOX CREEK									
VIKING A	97	0.75	0.05	69	3	66	1110	73	21790
SPIRIT RIVER	7	0.80	0.05	5		5	1180	6	
CADOMIN	46	0.85	0.05	37		37	1160	43	
TRIASSIC	3	0.90	0.10	2		2	1160	2	
FOX CREEK WEST									
CADOMIN	15	0.85	0.05	12		12	1160	14	
GARRINGTON									
MANNVILLE	12	0.85	0.10	9		9	1010	9	
MANNVILLE ASSOC	3	0.90	0.15	2		2	1010	2	
RUNDLE	2	0.85	0.10	1		1	1020	1	
LEDUC 23-35-4	23	0.85	0.20	15		15	1020	15	500
LEDUC (OTHER)	7	0.85	0.20	5	1	4	1020	4	
LEDUC ASSOC 36-35-4	15	0.85	0.20	10		10	1020	10	500

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1955 CONSIDERED BEYOND
									ECONOMIC REACH
		GIP BASED ON MATERIAL BALANCE					2680	1950	1968 NUL
									1963 NUL
									1965 NUL
25	0.20	0.30	1060	105	0.88	0.64	3470	1965	1969
									1965
									1961 CWNG
							5290	1950	1966 CWNG
									1966
									1969
									1969
9	0.16	0.10	3170	160	0.80	0.75	6710	1965	1969
							6870	1965	1969 TCPL
22	0.16	0.10	3170	150	0.79	0.75	6780	1965	1969
							7010	1965	1969 TCPL
									1969 TCPL
							8190	1955	1966 A&S
									1960
									1967
									1966
									1966 TCPL
13	0.14	0.45	630	180	0.92	0.57	2260	1957	1966 TCPL
									1966 TCPL
									1968 LOCAL UTILITY
28	0.23	0.50	490	70	0.93	0.58	1870	1956	1968 TCPL
7	0.24	0.20	690	70	0.92	0.58	2080	1916	1953 CWNG
									1966 LOCAL UTILITY
11	0.15	0.40	1480	140	0.85	0.67	5620	1957	1967 A&S
									1967
									1967 A&S
									1967
									1968
									1964
									1967
									1964
125	0.05	0.20	3760	220	0.94	0.75	10010	1954	1964
									1964 TCPL
85	0.05	0.20	3700	220	0.95	0.77	9880	1956	1964

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
GHOST PINE									
VIKING	9	0.80	0.05	7		7	1020	7	
UPPER MANN C & U	30	0.80	0.10	22	4	18	1030	19	4200
UPPER MANN G & P	42	0.80	0.10	30	17	13	1030	13	11300
UPPER MANNVILLE Q	27	0.80	0.10	20		20	1030	21	2390
LOWER MANNVILLE F	19	0.85	0.10	14	2	12	1030	12	1940
MANNVILLE (OTHER)	160	0.80	0.10	110	14	96	1030	99	
UPPER MANN W ASSOC	15	0.80	0.15	10	2	8	1050	8	5490
MANN ASSOC (OTHER)	23	0.75	0.15	15	1	14	1050	15	
PEKISKO B	17	0.80	0.10	12		12	1070	13	6520
RUNDLE (OTHER)	11	0.80	0.10	8	4	4	1070	4	
GILBY									
CARDIUM	2	0.85	0.10	2		2	1000	2	
VIKING ASSOC	4	0.80	0.05	3		3	1080*	3	
BASAL MANNVILLE D	33	0.80	0.15	22	6	16	1080*	17	2360
MANNVILLE (OTHER)	42	0.85	0.15	31		31	1080*	33	
MANNVILLE ASSOC	4	0.80	0.15	3		3	1080*	3	
BASAL MANN A & JUR D	230	0.85	0.10	180	31	149	1080*	161	5860
BASAL MANN H & JUR E	150	0.80	0.10	110	8	102	1080*	110	7840
JURASSIC A	75	0.80	0.04	58	5	53	1080*	57	6050
JURASSIC C	19	0.80	0.04	15	13	2	1080*	2	2010
JURASSIC (OTHER)	8	0.80	0.05	6		6	1080*	6	
JURASSIC B ASSOC	18	0.75	0.04	13		13	1080*	14	1220
RUNDLE C	260	0.85	0.05	210	79	131	1080*	141	8070
RUNDLE D	150	0.85	0.05	120	42	78	1080*	84	11240
RUNDLE H	16	0.85	0.05	13		13	1080*	14	2420
RUNDLE (OTHER)	17	0.85	0.05	13		13	1080*	14	
WABAMUN	7	0.90	0.20	5		5	1170	6	
GLENEVIS									
MANNVILLE	16	0.80	0.10	12		12	1040	12	
GLEN PARK									
MANNVILLE	6	0.80	0.05	4		4	1140	5	
D-3 SOLN	16	0.65	0.15	9	2	7	1250	9	
GOLD CREEK									
SPIRIT RIVER A	58	0.85	0.05	47		47	1050	49	3940
BLUESKY-GETHING A	63	0.85	0.10	48		48	1050	50	10230
GETHING	4	0.85	0.10	3		3	1050	3	
CADOMIN	11	0.80	0.15	9		9	1110*	10	
WABAMUN A	410	0.80	0.30	230		230	1040*	239	9400
ABAMUN B	92	0.80	0.30	51		51	1040*	53	1100
GOLDEN SPIKE									
VIKING	8	0.80	0.05	6	1	5	1050	5	
BLAIRMORE	14	0.80	0.05	11	1	10	1050	11	
D-1 A	25	0.90	0.10	20	13	7	1060	7	1260
D-2 ASSOC	3	0.85	0.15	3		3	1120	3	
D-2 SOLN	8	0.65	0.20	4	1	3	1120*	3	
D-3 A ASSOC		0.90	0.10		-56	56	1100*	62	
D-3 A SOLN	130	0.90	0.40	69	28	41	1130*	46	
GOODWIN									
MANNVILLE	1	0.75	0.10	1		1	1050	1	
JURASSIC A	20	0.85	0.10	15		15	1070	16	4560

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1967	2
11	0.20	0.35	1540	115	0.81	0.70	4630	1964	1967 TCPL	3
6	0.20	0.35	1510	120	0.81	0.69	4580	1964	1967 TCPL	4
18	0.20	0.35	1520	125	0.81	0.67	4780	1955	1967 TCPL	5
										6
18	0.20	0.45	1550	125	0.82	0.68	4850	1955	1969 TCPL	7
									1967 TCPL	8
6	0.18	0.50	1520	110	0.75	0.76	4580	1963	1967 TCPL	9
									1967 TCPL	10
15	0.05	0.30	1620	125	0.82	0.69	5060	1962	1967	11
										12
									1967 TCPL	13
										14
										15
									1965	16
									1965	17
27	0.11	0.30	2250	160	0.83	0.70	6930	1962	1966 TCPL	18
									1966	19
										20
									1967	21
53	0.14	0.30	2310	155	0.81	0.72	7130	1956	1967 TCPL	22
32	0.12	0.35	2310	155	0.81	0.72	6960	1956	1965 TCPL	23
17	0.14	0.30	2300	150	0.81	0.73	6840	1953	1968 TCPL	24
13	0.15	0.30	2280	155	0.82	0.73	6920	1955	1968 TCPL	25
										26
									1968	27
16	0.16	0.20	2310	160	0.82	0.73	6990	1958	1968	28
55	0.10	0.15	2290	160	0.82	0.73	6970	1955	1968 TCPL	29
32	0.07	0.20	2280	155	0.82	0.73	6770	1955	1968 TCPL	30
29	0.04	0.20	2320	170	0.83	0.72	7210	1961	1968	31
										32
									1968	33
									1961	34
										35
										36
									1966	37
										38
										39
									1965 NUL	40
									1966 NUL	41
										42
										43
24	0.15	0.15	1930	150	0.85	0.65	6470	1968	1968	44
6	0.12	0.20	3210	160	0.82	0.73	7110	1968	1969	45
									1968	46
									1968	47
										48
64	0.07	0.15	5150	215	1.00	0.99	10880	1964	1967	49
122	0.07	0.15	5150	215	1.00	0.99	10900	1964	1968	50
										51
										52
									1965 INJECTED INTO D-3	53
									1968 INJECTED INTO D-3	54
53	0.09	0.20	1580	125	0.82	0.68	4440	1949	1955 INJECTED INTO D-3	55
									1966	56
										57
									1965 INJECTED INTO D-3	58
									1968	59
							5650	1949	1966 INJECTED INTO D-3	60
										61
										62
									1964	63
18	0.20	0.30	2010	160	0.86	0.66	5900	1956	1964	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
GORDONDALE									
PEACE RIVER A	34	0.85	0.05	27	26	1	1000	1	9190
PEACE RIVER (OTHER)	1	0.85	0.05	1		1	1000	1	
SPIRIT RIVER	6	0.85	0.05	5		5	1000	5	
GETHING A	39	0.75	0.03	29	18	11	1020	11	
GETHING (OTHER)	11	0.90	0.05	9	9	¤ 1	1020	¤ 1	
CADOMIN	19	0.85	0.05	15	4	11	1020	11	
GREENCOURT									
JURASSIC A	46	0.80	0.10	33		33	1070	35	7730
JURASSIC B	14	0.80	0.05	10		10	1070	11	3770
RUNDLE	3	0.80	0.05	2		2	1130	2	
PEKISKO A ASSOC	130	0.85	0.10	98		98	1130	111	7830
HACKETT									
MANNVILLE A	60	0.90	0.10	49	9	40	1100	44	3420
MANNVILLE (OTHER)	2	0.90	0.10	1		1	1100	1	
HAIRY HILL									
VIKING	2	0.75	0.05	1		1	980	1	
COLONY A	22	0.90	0.05	19	14	5	1000*	5	3220
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000*	1	
NISKU	3	0.80	0.05	2		2	1000	2	
HALLIDAY									
VIKING	5	0.80	0.05	4	1	3	1040	3	
HAMELIN CREEK									
PEACE RIVER	3	0.80	0.05	2		2	1000	2	
GETHING	3	0.80	0.05	3		3	1010	3	
CADOMIN A	37	0.85	0.05	30	5	25	1060	27	
TRIASSIC	2	0.75	0.05	1		1	1160	1	
HANNA									
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	3	0.85	0.05	2		2	1050	2	
BANFF	2	0.80	0.05	1		1	1080	1	
HARMATTAN EAST									
RUNDLE ASSOC	1060	0.85	0.11	800	-16	816	1080*	881	49300
RUNDLE SOLN	190	0.65	0.25	92	16	76	1080*	82	
HARMATTAN-ELKTON									
BLAIRMORE	3	0.90	0.05	2		2	1020	2	
RUNDLE A	47	0.25	0.14	10	5	5	1100	6	2300
RUNDLE B ASSOC	28	0.85	0.15	21	10	11	1080*	12	7140
RUNDLE C ASSOC	1150	0.90	0.15	880	-72	952	1080*	1028	19020
RUNDLE C SOLN	180	0.65	0.30	83	60	23	1080*	25	
D-3 A	430	0.80	0.68	110	12	98	960	94	10120
HEART RIVER									
PEACE RIVER	2	0.85	0.05	2	1	1	1000	1	
SPIRIT RIVER	2	0.90	0.05	2	1	1	1000	1	
HERCULES									
VIKING	20	0.85	0.05	17		17	1050	18	
MANNVILLE	7	0.80	0.05	6	1	5	960	5	
HIGH PRAIRIE									
PEACE RIVER	3	0.85	0.05	3		3	1000	3	
SPIRIT RIVER	8	0.85	0.05	6		6	1100	7	
GETHING	2	0.85	0.05	1		1	1000	1	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
15	0.19	0.30	620	90	0.93	0.57	2740	1952	1962 WESTCOAST	2
									1962	3
									1969	4
		GIP BASED ON MATERIAL BALANCE					4240	1953	1969 WESTCOAST	5
										6
									1969 WESTCOAST	7
									1969 WESTCOAST	8
										9
										10
19	0.13	0.55	1620	115	0.82	0.66	4720	1958	1969	11
11	0.15	0.45	1600	140	0.83	0.69	4810	1967	1969	12
									1968	13
39	0.12	0.25	1620	145	0.85	0.64	4740	1961	1969	14
										15
										16
105	0.18	0.30	1220	135	0.85	0.65	3840	1952	1963 TCPL	17
									1963	18
										19
										20
									1961	21
21	0.24	0.30	630	70	0.91	0.60	1790	1954	1961 WESTERN MINERALS	22
									1966	23
									1966	24
										25
										26
									1961 TCPL	27
										28
										29
									1962	30
									1961	31
		GIP BASED ON MATERIAL BALANCE					3310	1951	1968 LOCAL UTILITY	32
									1961	33
										34
										35
									1966	36
									1957	37
									1957 LOCAL UTILITY	38
										39
										40
30	0.10	0.25	3430	185	0.84	0.84	8390	1954	1969 POOL BEING CYCLED	41
							8620	1954	1969 INJ INTO GAS CAP	42
										43
										44
									1966	45
33	0.08	0.20	3630	205	0.89	0.71	9150	1957	1969 TCPL	46
6	0.09	0.20	3430	195	0.85	0.82	8960	1955	1964 INJ INTO RUNDLE C	47
70	0.11	0.20	3630	200	0.84	0.84	8990	1954	1964 POOL BEING CYCLED	48
										49
							9130	1954	1966 INJ INTO GAS CAP	50
70	0.05	0.10	4680	230	0.77	0.93	11000	1961	1969 A&S	51
										52
										53
									1964 LOCAL UTILITY	54
									1964 LOCAL UTILITY	55
										56
										57
									1955	58
									1966 NUL	59
										60
										61
									1961 CONSIDERED BEYOND	62
									1961 ECONOMIC REACH	63
									1961	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
HOLBURN									
CARDIUM	8	0.80	0.05	6	3	3	980	3	
MANNVILLE	16	0.85	0.10	12	1	11	1120	12	
HOLMBERG									
MANNVILLE A	15	0.85	0.05	12		12	1050	13	2100
MANNVILLE (OTHER)	11	0.85	0.05	9		9	1050	9	
HOMEGLEN-RIMBEY									
D-3 ASSOC	1170	0.75	0.15	760**					
D-3 SOLN	86	0.50	0.15	37**					12800
					298**	499	1020*	509	
HUNTER VALLEY									
RUNDLE A	73	0.85	0.25	47		47	1000	47	1570
RUNDLE (OTHER)	5	0.85	0.25	3		3	1000	3	
HUSSAR									
BELLY RIVER	4	0.75	0.05	3	2	1	1000	1	
VIKING B	32	0.75	0.05	22	4	18	1020*	18	13000
VIKING E	24	0.80	0.05	18	6	12	1020*	12	13590
VIKING (OTHER)	22	0.80	0.05	17	3	14	1020*	14	
BASAL COLORADO A	26	0.75	0.05	19	8	11	1020*	11	16390
BASAL COLORADO C	26	0.75	0.05	19	10	9	1030*	9	16080
BSL COLORADO (OTHER)	4	0.80	0.05	3	1	2	1030*	2	
GLAUCONITIC N	110	0.85	0.05	87	62	25	1030*	26	
GLAUCONITIC P	17	0.85	0.05	14	12	2	1030*	2	500
GLAUCONITIC R	20	0.85	0.05	16	10	6	1030*	6	500
OSTRACOD F	27	0.80	0.05	20	1	19	1030*	20	8300
OSTRACOD R	26	0.85	0.05	21	2	19	1030*	20	7480
BASAL MANNVILLE B	30	0.85	0.05	25		25	1030*	26	1330
BASAL MANNVILLE D	11	0.90	0.05	10	1	9	1030*	9	530
MANNVILLE (OTHER)	100	0.85	0.05	82	16	66	1030*	68	
GLAUCONITIC A ASSOC	75	0.85	0.05	61**					
GLAUCONITIC A SOLN	20	0.65	0.25	10**	27**	44	1030*	45	5290
GLAUCONITIC B ASSOC	19	0.85	0.05	15	11	4	1030*	4	3900
MANN ASSOC (OTHER)	29	0.85	0.05	23	2	21	1030*	22	
INLAND									
VIKING A	17	0.80	0.05	13		13	980	13	15300
MANNVILLE	2	0.80	0.10	1		1	1000	1	
INNISFAIL									
BLAIRMORE ASSOC	1	0.80	0.15	1		1	1050	1	
RUNDLE	22	0.90	0.10	18		18	1080	19	
WABAMUN	3	0.85	0.15	2		2	1080	2	
D-3 ASSOC	17	0.90	0.35	10		10	1020	10	1220
D-3 SOLN	200	0.55	0.45	60	19	41	1130*	46	
IRRICANA									
WABAMUN A	27	0.85	0.50	11	1	10	980	10	3296
JARVIE									
VIKING	10	0.80	0.05	7		7	1040	7	
MANNVILLE	9	0.85	0.05	8		8	1100	9	
JENNER									
BOW ISLAND	6	0.75	0.05	3		3	990	3	
BASAL COLORADO	8	0.85	0.05	6		6	1040	6	
BASAL COLORADO ASSOC	1	0.85	0.15	1		1	1040	1	
MANNVILLE	24	0.80	0.05	19		19	1050	20	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
										1
									1966 GOLDEN SPIKE INJ	2
									1968 GOLDEN SPIKE INJ	3
										4
										5
13	0.20	0.30	1100	95	0.81	0.70	3420	1952	1960 BAROID OF CANADA	6
									1958	7
										8
										9
173	0.07	0.10	2830	180	0.85	0.70	7840	1953	1964	10
							7920	1953	1964 TCPL AND A&S	11
										12
										13
83	0.07	0.20	3580	145	0.84	0.68	9280	1962	1964	14
									1964	15
										16
										17
									1961 TCPL	18
5	0.20	0.30	1120	105	0.88	0.63	4040	1955	1961 TCPL	19
6	0.20	0.30	1150	100	0.89	0.63	3740	1961	1966 TCPL	20
									1961 TCPL	21
										22
3	0.17	0.30	1240	110	0.88	0.61	4330	1952	1961 TCPL	23
4	0.18	0.30	1230	110	0.88	0.63	4120	1955	1964 TCPL	24
									1965 TCPL	25
		GIP BASED ON MATERIAL BALANCE					4470	1955	1969 TCPL	26
48	0.21	0.30	1490	110	0.82	0.65	4510	1957	1968 TCPL	27
										28
56	0.21	0.30	1490	110	0.83	0.64	4650	1960	1967 TCPL	29
5	0.21	0.25	1370	110	0.84	0.65	4570	1956	1964 TCPL	30
5	0.20	0.35	1510	115	0.82	0.65	4660	1956	1965 TCPL	31
45	0.15	0.30	1470	105	0.82	0.67	4330	1960	1963	32
38	0.16	0.30	1510	115	0.83	0.66	4820	1955	1961 TCPL	33
										34
									1968 TCPL	35
17	0.22	0.25	1480	110	0.83	0.64	4690	1952	1967	36
							4650	1952	1967 TCPL	37
7	0.20	0.30	1470	110	0.83	0.67	4700	1956	1967 TCPL	38
									1968 TCPL	39
										40
										41
3	0.22	0.40	800	80	0.90	0.60	2190	1959	1963 CONSIDERED BEYOND	42
									1963 ECONOMIC REACH	43
										44
										45
									1965	46
									1961	47
									1961	48
28	0.06	0.15	3550	95	0.84	0.81	8440	1957	1961	49
										50
							8580	1957	1965 TCPL	51
										52
										53
13	0.06	0.85	3530	625	0.71	0.90	7602	1958	1968 WESTCOAST	54
										55
										56
									1960 CONSIDERED BEYOND	57
									1956 ECONOMIC REACH	58
										59
										60
									1961	61
									1961	62
									1969	63
									1961	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
JENNER (CONTINUED)									
MANNVILLE ASSOC	9	0.85	0.05	7		7	1050	7	
RUNDLE	1	0.85	0.05	1		1	1000	1	
RUNDLE ASSOC	3	0.85	0.05	2		2	1000	2	
JOARCAM									
VIKING	3	0.75	0.05	2		2	1040	2	
VIKING ASSOC	70	0.75	0.35	35	-2	37	1040	38	13520
VIKING SOLN	42	0.35	0.65	9	2	7	1050	7	
MANNVILLE 30-50-22	15	0.90	0.05	13		13	960	12	500
MANNVILLE (OTHER)	3	0.90	0.05	3		3	960	3	
JOFFRE									
VIKING	1	0.75	0.10	1		1	1000	1	
BLAIRMORE	41	0.85	0.10	32	1	31	1020	32	
LEDUC ASSOC	2	0.85	0.15	2		2	1050	2	
JUDY CREEK									
VIKING A	54	0.80	0.05	41	14	27	1010	27	23330
BH LK A SOLN	560	0.45	0.30	180	24	156	1090*	170	
BH LK B SOLN	270	0.50	0.30	93	11	82	1090*	89	
JUDY CREEK SOUTH									
RUNDLE A	13	0.90	0.10	10		10	1050*	11	500
JUMPING POUND									
MISSISSIPPIAN	780	0.85	0.15	560	287	273	1050*	287	7090
JUMPING POUND WEST									
RUNDLE A	1090	0.80	0.20	700	22	678	1050*	712	12600
RUNDLE B .	280	0.80	0.20	180	3	177	1050*	186	3400
RUNDLE C	130	0.80	0.20	80		80	1050*	84	1720
KAYBOB									
NOTIKEWIN A	200	0.85	0.05	160	35	125	1100*	138	25650
NOTIKEWIN B	170	0.85	0.05	140	61	79	1100*	87	
NOTIKEWIN D	17	0.85	0.05	14		14	1100*	15	5660
SPIRIT RIVER (OTHER)	15	0.85	0.05	12		12	1000	12	
GETHING	16	0.85	0.05	13		13	1050	14	
CADOMIN	48	0.85	0.05	38		38	1040	40	
CADOMIN B ASSOC	76	0.85	0.05	62		62	1040	64	6110
CADOMIN ASSOC	6	0.80	0.05	4		4	1040	4	
WABAMUN	1	0.80	0.10	1		1	1070	1	
NISKU	5	0.85	0.35	3		3	1070	3	
BEAVERHILL LAKE	1	0.80	0.15	1		1	1070	1	
BH LK ASSOC	6	0.80	0.15	4		4	1140*	5	
BH LK A SOLN	340	0.40	0.25	100	16	84	1140*	96	
KAYBOB SOUTH									
VIKING A	30	0.75	0.05	21	2	19	1120	21	30350
CADOMIN A	39	0.80	0.05	30	2	28	1070*	30	8390
CADOMIN B	27	0.80	0.05	20		20	1070*	21	3430
CADOMIN C	17	0.80	0.05	13		13	1070*	14	3122
CADOMIN (OTHER)	8	0.75	0.05	6		6	1070*	6	
TRIASSIC	3	0.80	0.05	2		2	1160*	2	
TRIASSIC ASSOC	2	0.80	0.05	2		2	1160*	2	
TRIASSIC SOLN	99	0.40	0.25	30		30	1160*	35	
NISKU A	19	0.90	0.20	14		14	1160*	16	1100

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1966	2
									1965	3
									1965	4
										5
										6
									1963	7
19	0.17	0.40	870	100	0.89	0.65	3240	1949	1968	8
							3250	1949	1968 GAS FLOOD	9
57	0.20	0.35	1250	100	0.86	0.60	3980	1960	1961	10
										11
									1961	12
										13
										14
									1967	15
									1967 LOCAL UTILITY	16
									1967	17
										18
										19
6	0.18	0.35	1290	130	0.88	0.63	4610	1959	1968 NUL AND A&S	20
							8660	1959	1966 NUL AND A&S	21
							8840	1959	1966 NUL AND A&S	22
										23
										24
56	0.10	0.20	1900	155	0.86	0.63	6040	1960	1960 CONSIDERED BEYOND	25
									ECONOMIC REACH	26
										27
										28
141	0.08	0.10	3980	195	0.90	0.71	9590	1944	1964 CWNG	29
										30
										31
140	0.07	0.15	4250	185	0.92	0.74	10830	1961	1969 CWNG	32
132	0.07	0.15	4320	190	0.93	0.75	11550	1963	1969 CWNG AND TCPL	33
130	0.06	0.15	4350	180	0.91	0.75	11500	1967	1969 TCPL	34
										35
										36
13	0.20	0.35	1530	135	0.88	0.61	4690	1957	1967 A&S	37
		GIP BASED ON MATERIAL BALANCE					4820	1958	1968 A&S	38
6	0.19	0.35	1390	145	0.88	0.61	5050	1958	1966	39
									1964	40
										41
									1964	42
									1964	43
17	0.16	0.30	2210	160	0.84	0.72	5800	1962	1964	44
									1968	45
									1961	46
										47
									1961	48
									1964	49
									1962	50
							9780	1957	1965 A&S	51
										52
										53
6	0.14	0.40	1460	150	0.86	0.66	5710	1960	1968 A&S	54
8	0.15	0.35	2230	180	0.87	0.64	6710	1961	1966 A&S	55
13	0.15	0.35	2230	180	0.87	0.64	6750	1963	1966	56
9	0.15	0.35	2230	180	0.87	0.64	6750	1961	1966	57
										58
									1967	59
									1964	60
									1963	61
							6980	1962	1969 A&S	62
4	0.05	0.20	4100	225	0.93	0.80	9510	1958	1963	63

TABLF A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROV

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU.FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
KAYBOB SOUTH (CONTINUED)									
NISKU (OTHER)	1	0.80	0.05	1		1	1160*	1	
BEAVERHILL LAKE A	4420	0.80	0.35	2300	24	2276	1090*	2481	58860
KILLAM									
VIKING	6	0.80	0.05	4		4	1010	4	
MANNVILLE	14	0.75	0.05	10		10	1000	10	
NISKU	1	0.80	0.05	1		1	1170	1	
KILLAM NORTH									
MANNVILLE	19	0.80	0.05	15	1	14	1000	14	
MANNVILLE ASSOC	5	0.80	0.05	4		4	1000	4	
KNAPPEN									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
JURASSIC	8	0.80	0.05	6		6	1000	6	
MISSISSIPPIAN	7	0.90	0.10	6		6	1000	6	
KNELLER									
MANNVILLE	11	0.85	0.05	9	1	8	1000	8	
KNOPCIK									
DOE CREEK A	18	0.75	0.05	12	1	11	1000	11	4360
PEACE RIVER	1	0.80	0.05	1		1	1020	1	
LAC LA BICHE									
MANNVILLE	10	0.80	0.05	8	1	7	1010	7	
LEAHURST									
MANNVILLE	25	0.65	0.05	15	2	13	1160*	15	
LEDUC-WOODBEND									
CARDIUM	12	0.80	0.05	9	7	2	1040	2	
VIKING	20	0.80	0.05	15	3	12	1070	13	
BLAIRMORE	42	0.85	0.05	33	19	14	1180	17	
BLAIRMORE ASSOC	57	0.85	0.05	45	2	43	1180	51	
D-1	2	0.85	0.10	2	2	¤ 1	1050	¤ 1	
D-1 ASSOC	4	0.85	0.10	3		3	1050	3	
D-2 A ASSOC	37	0.90	0.15	28	-12	40	1180	47	9770
D-2 A SOLN	130	0.75	0.30	70	64	6	1180	7	
D-2 B SOLN	41	0.75	0.30	21	15	6	1180	7	
D-3 A ASSOC	420	0.85	0.15	300	-7	307	1180	362	17490
D-3 ASSOC (OTHER)	6	0.85	0.15	4	1	3	1180	4	
D-3 A SOLN	140	0.70	0.30	70	60	10	1180	12	
D-3 SOLN (OTHER)	9	0.70	0.30	5	4	1	1180	1	
LEGAL									
MANNVILLE	4	0.75	0.05	4	2	2	1030	2	
LINDBERGH									
VIKING	4	0.65	0.05	2		2	990	2	
MANNVILLE	18	0.80	0.05	14	8	6	1000	6	
LITTLE BOW									
UPPER MANNVILLE A	20	0.85	0.05	16	3	13	1000	13	3440
MANNVILLE (OTHER)	17	0.85	0.05	14	2	12	1000	12	
MANNVILLE ASSOC	1	0.85	0.05	1		1	1000	1	
LLOYDMINSTER									
MANNVILLE	24	0.85	0.30	14	12	2	950	2	
LONE PINE CREEK									
MANNVILLE	2	0.80	0.10	1		1	1020	1	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1958
102	0.08	0.20	4600	240	0.87	1.00	10560	1961	1969 POOL BEING CYCLED
									1968
									1968
									1968
									1966 LOCAL UTILITY
									1966
									1966 CMG
									1967 CMG
									1965
									1968 LOCAL UTILITY
9	0.22	0.30	900	100	0.87	0.66	2920	1964	1966 LOCAL UTILITY
									1964
									1968 LOCAL UTILITY
									1969 LOCAL UTILITY
									1967 INJECTED INTO D-2
									1959 AND D-3 GAS CAPS
									1959 AND SOLD TO NUL
									1961
									1969
									1966
41	0.02	0.20	1780	150	0.80	0.73	5050	1947	1958
							5100	1947	1965
							5260	1947	1965
60	0.08	0.15	1890	150	0.83	0.66	5300	1947	1964
									1964
							5320	1947	1966
									1966
									1955 CIGOL
									1961 CANSALT
									1962 CANSALT
8	0.21	0.40	1680	105	0.82	0.67	3950	1965	1968 TCPL
									1968 TCPL
									1968
									1966 LOCAL UTILITY
									1963

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
LONE PINE CREEK (CONTINUED)									
WABAMUN A	400	0.85	0.20	270	17	253	1000	253	27270
D-3 A ASSOC	120	0.85	0.25	76**					3470
D-3 A SOLN	10	0.65	0.30	5**	4**	77	1060*	82	
D-3 ASSOC (OTHER)	9	0.85	0.20	6		6	1060*	6	
LONG COULEE									
MANNVILLE A	16	0.85	0.25	10	1	9	1000	9	2070
MANNVILLE (OTHER)	11	0.85	0.20	7		7	1000	7	
LOOKOUT BUTTE									
RUNDLE A	660	0.80	0.15	450	83	367	1060*	389	7280
LOVETT RIVER									
BLAIRMORE 2-47-19	12	0.90	0.05	10		10	1040	10	1100
RUNDLE A	97	0.80	0.10	70		70	1040	73	1100
MAJEAU LAKE									
MANNVILLE	2	0.80	0.05	2		2	1000	2	
BANFF 25-56-4	12	0.90	0.10	10		10	1070	11	500
MALMO									
VIKING	8	0.85	0.05	6		6	1000	6	
BLAIRMORE	8	0.85	0.10	6		6	1030	6	
BLAIRMORE ASSOC	2	0.70	0.15	1		1	1030	1	
D-2 ASSOC	4	0.80	0.20	3		3	1100	3	
D-3 B	42	0.85	0.20	29		29	1100	32	1960
D-3 ASSOC	2	0.85	0.15	1		1	1100	1	
MANYBERRIES									
BOW ISLAND A	28	0.90	0.02	25	23	2	940	2	
BOW ISLAND (OTHER)	5	0.65	0.02	3		3	940	3	
MANNVILLE	2	0.80	0.05	1		1	1000	1	
MARLBORO									
LEDUC A	170	0.85	0.25	100		100	1000	100	1920
MARSH HEAD CREEK									
LEDUC 17-59-20	27	0.85	0.35	15		15	1050	16	500
MARTEN HILLS									
PELICAN	2	0.65	0.05	1		1	990	1	
MANNVILLE (OTHER)	27	0.80	0.05	19		19	990	19	
WBSK A & WAB A	1210	0.75	0.05	860	4	856	990	847	180000
WABAMUN B	14	0.75	0.05	10		10	1000	10	4280
WABAMUN (OTHER)	2	0.75	0.05	2		2	1000	2	
MATZIWIN									
VIKING	11	0.85	0.05	9		9	1090	10	
MANNVILLE	1	0.80	0.05	1		1	1090	1	
MAZEPPA									
RUNDLE 16-19-27	20	0.90	0.15	15		15	1060	16	1100
WABAMUN	11	0.85	0.45	5		5	1000	5	
MEDICINE HAT									
MEDICINE HAT	2550	0.80	0.02	2000	629	1371	970	1330	983680
BOW ISLAND	15	0.60	0.05	9	1	8	970	8	
JURASSIC	6	0.80	0.05	5	2	3	1000	3	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
34	0.06	0.20	3570	180	0.89	0.76	7850	1955	1969 TCPL	2
48	0.08	0.15	3260	165	0.81	0.78	7860	1963	1969	3
									1967 TCPL	4
										5
									1967	6
										7
										8
9	0.20	0.35	1880	105	0.78	0.83	4380	1965	1968 TCPL	9
									1968	10
										11
										12
153	0.07	0.20	4770	190	0.96	0.72	12060	1959	1967 TCPL	13
										14
										15
9	0.15	0.25	4300	190	0.96	0.62	10010	1959	1959	16
177	0.06	0.20	4950	220	1.01	0.61	11870	1958	1959	17
										18
										19
									1955 CONSIDERED BEYOND	20
60	0.09	0.15	1500	125	0.82	0.67	4250	1951	1955 ECONOMIC REACH	21
										22
										23
									1960	24
									1959	25
									1960	26
									1959	27
										28
46	0.07	0.10	2180	130	0.81	0.76	5990	1959	1966	29
									1966	30
										31
										32
		GIP BASED ON MATERIAL BALANCE					2570	1947	1967 CMG	33
									1967	34
									1957	35
										36
										37
129	0.07	0.10	5050	265	0.97	0.74	12150	1965	1969	38
										39
										40
29	0.06	0.15	4800	245	0.92	0.66	11540	1961	1964 CONSIDERED BEYOND	41
									ECONOMIC REACH	42
										43
										44
									1964	45
									1969	46
38	0.21	0.45	390	80	0.95	0.57	2260	1961	1969 TCPL	47
20	0.21	0.35	390	80	0.95	0.57	2010	1967	1969	48
										49
									1969	50
										51
										52
									1962	53
									1961	54
										55
										56
33	0.08	0.20	2700	145	0.81	0.71	6800	1956	1957 CONSIDERED BEYOND	57
									1967 ECONOMIC REACH	58
										59
										60
8	0.26	0.40	630	60	0.91	0.57	1600	1904	1967 TCPL, MANY ISLANDS	61
									AND LOCAL UTILITY	62
									1964 TCPL	63
									1968 TCPL	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
MEDICINE RIVER									
BASAL MANNVILLE A	34	0.85	0.15	25		25	1150*	29	3680
MANNVILLE (OTHER)	77	0.85	0.15	55		55	1150*	63	
OSTRACOD B ASSOC	14	0.85	0.15	10		10	1150*	12	3980
OSTRACOD C ASSOC	40	0.85	0.15	29	4	25	1150*	29	2900
BASAL QUARTZ B ASSOC	32	0.85	0.15	23		23	1150*	26	2310
MANN ASSOC (OTHER)	31	0.85	0.15	22		22	1150*	25	
GLAUCONITIC A SOLN	98	0.60	0.45	32		32	1150*	37	
MANN SOLN (OTHER)	38	0.50	0.45	10		10	1150*	12	
JURASSIC	15	0.85	0.15	11		11	1020*	11	
JURASSIC D ASSOC	15	0.80	0.15	10		10	1020*	10	910
JUR ASSOC (OTHER)	16	0.80	0.15	11		11	1020*	11	
JURASSIC SOLN	70	0.65	0.45	25		25	1020*	26	
PEKISKO P	65	0.80	0.11	47	2	45	1100*	50	3220
RUNDLE (OTHER)	20	0.85	0.15	14	1	13	1100*	14	
RUNDLE ASSOC	9	0.85	0.15	6		6	1100*	7	
RUNDLE SOLN	36	0.60	0.45	12		12	1200*	14	
LEDUC ASSOC	2	0.85	0.20	1		1	1100*	1	
MIKWAN									
VIKING	7	0.75	0.05	5		5	1000	5	
MANNVILLE	10	0.80	0.05	7		7	1100	8	
MANNVILLE ASSOC	1	0.75	0.05	1		1	1100	1	
MILLET									
MANNVILLE 1-49-25	25	0.50	0.05	12		12	1020	12	5880
MANNVILLE (OTHER)	5	0.80	0.10	3		3	1020	3	
MINNEHIK-BUCK LAKE									
MANNVILLE	6	0.80	0.05	4		4	1000	4	
PEKISKO A'	740	0.85	0.12	550	123	427	1120*	478	
PEKISKO B	71	0.85	0.10	54	2	52	1120*	58	7620
MITSUE									
MANNVILLE	2	0.80	0.05	1		1	1070	1	
GILWOOD ASSOC	3	0.90	0.25	2		2	1170	2	
GILWOOD A SOLN	470	0.50	0.25	180		180	1170	211	
MOOSE									
RUNDLE A	86	0.80	0.20	55		55	1000	55	1900
MORINVILLE									
VIKING	4	0.75	0.05	3		3	1000	3	
LOWER MANNVILLE A	52	0.75	0.05	37	16	21	1070*	22	6040
LOWER MANNVILLE C	22	0.75	0.08	13	9	4	1070*	4	
MANNVILLE (OTHER)	59	0.80	0.05	46	22	24	1070*	26	
MOUNTAIN PARK									
TRIASSIC 36-47-22	21	0.85	0.05	17		17	1090	19	1100
MURIEL LAKE									
MANNVILLE	9	0.75	0.05	6	1	5	1000	5	
NEVIS									
BLAIRMORE A	64	0.85	0.10	49		49	1000	49	11990
BLAIRMORE (OTHER)	2	0.85	0.10	1		1	1000	1	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
12	0.14	0.30	2640	160	0.81	0.71	7660	1958	1968
									1968
5	0.13	0.35	2830	155	0.80	0.76	7010	1954	1968
14	0.14	0.25	2930	150	0.79	0.76	7480	1960	1968 TCPL
19	0.14	0.30	2380	150	0.81	0.72	7000	1959	1968
									1968
							7400	1964	1969
									1968
									1968
22	0.15	0.30	2340	145	0.81	0.70	6970	1962	1968
									1968
									1968
36	0.10	0.25	2380	140	0.79	0.74	6950	1963	1969 TCPL
									1968 TCPL
									1968
									1968
									1968
									1969
									1960
									1968
7	0.20	0.70	1500	120	0.79	0.71	4440	1951	1968 CONSIDERED BEYOND
									1957 ECONOMIC REACH
									1959
		GIP BASED ON MATERIAL BALANCE					6910	1952	1969 A&S
19	0.10	0.25	2490	185	0.85	0.71	7300	1962	1966 A&S
									1968
									1966
							5680	1964	1968
140	0.06	0.15	1870	115	0.77	0.73	7570	1960	1969
									1962
16	0.22	0.30	1140	115	0.87	0.67	3600	1952	1969 CIGOL AND LOCAL UTILITY
		GIP BASED ON MATERIAL BALANCE					3690	1951	1969 CIGOL AND LOCAL UTILITY
									1962 CIGOL AND LOCAL UTILITY
36	0.07	0.20	4100	240	0.98	0.62	10120	1956	1969 CONSIDERED BEYOND ECONOMIC REACH
									1964 LOCAL UTILITY
10	0.22	0.20	1400	130	0.84	0.66	4750	1952	1959
									1964

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
NEVIS (CONTINUED)									
DEVONIAN	1040	0.90	0.15	800	219	581	1000*	581	31000
NEW NORWAY									
VIKING	3	0.80	0.10	2		2	1000	2	
BLAIRMORE	10	0.85	0.05	9		9	1010	9	
NIPISI									
GILWOOD A SOLN	250	0.55	0.25	100		100	1150	115	
NITON									
MANNVILLE	6	0.80	0.05	5		5	1070	5	
CADOMIN	8	0.90	0.05	7		7	1070	7	
NORDEGG									
TRIASSIC	9	0.90	0.10	7		7	1000	7	
RUNDLE 17-41-17	25	0.90	0.10	20		20	1000	20	2130
NORMANDVILLE									
PEACE RIVER	1	0.70	0.05	1		1	990	1	
GETHING	6	0.85	0.05	5		5	980	5	
TRIASSIC	1	0.85	0.05	1		1	1090	1	
BELLOY	2	0.85	0.05	2		2	1060	2	
MISSISSIPPIAN A	16	0.85	0.05	13	2	11	1050	12	1410
MISS (OTHER)	22	0.85	0.05	18	2	16	1050	17	
OBED									
VIKING 26-55-22	14	0.85	0.05	12		12	1020	12	1100
MANNVILLE	6	0.85	0.05	5		5	1040	5	
RUNDLE	4	0.85	0.10	4		4	1050	4	
D-2 A	220	0.90	0.35	130		130	1060	138	
OBERLIN									
MANNVILLE	3	0.70	0.05	2	2	□ 1	1090	□ 1	
OKOTOKS									
CROSSFIELD	470	0.80	0.55	170	54	116	1000	116	21990
OLDS									
VIKING	3	0.65	0.05	2		2	1040*	2	
WABAMUN B	31	0.85	0.25	20		20	1000*	20	1100
WABAMUN A ASSOC	350	0.85	0.25	220**					31030
WABAMUN A SOLN	62	0.65	0.40	24**	52**	192	1000*	192	
OPEN CREEK									
BASAL QUARTZ A	14	0.85	0.10	11		11	1080*	12	500
MANNVILLE (OTHER)	19	0.90	0.15	14		14	1080*	15	
RUNDLE	11	0.85	0.10	8		8	1080*	9	
OWLSEYE									
MANNVILLE	2	0.85	0.05	2		2	1020	2	
OYEN									
VIKING A	51	0.80	0.10	37	5	32	980	31	14260
VIKING C	13	0.80	0.05	10	6	4	980	4	
VIKING (OTHER)	3	0.80	0.05	2		2	980	2	
DETRITAL	11	0.85	0.05	9	2	7	1010	7	
PADDLE RIVER									
JURASSIC-DETRITAL	180	0.80	0.10	130	22	108	1130*	122	30000
JURASSIC (OTHER)	2	0.80	0.10	1		1	1130*	1	
RUNDLE ASSOC	36	0.85	0.10	27		27	1060	29	9300

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
75	0.07	0.15	2340	140	0.81	0.69	5580	1952	1968 TCPL	2
									1959	5
									1959	6
									1965	9
									1969	12
									1963	13
									1961 CONSIDERED BEYOND	16
70	0.04	0.20	1840	125	0.86	0.58	4930	1960	1961 ECONOMIC REACH	17
									1967	20
									1967	21
									1967	22
									1967	23
13	0.27	0.35	1570	100	0.83	0.64	3440	1956	1967 LOCAL UTILITY	25
									1967 LOCAL UTILITY	26
15	0.14	0.40	3830	165	0.92	0.62	8080	1967	1967	29
									1969	30
									1966	31
		CONFIDENTIAL							1969	32
									1967 LOCAL UTILITY	35
39	0.06	0.20	3600	175	0.70	0.90	8710	1951	1966 CWNG	38
									1965	41
68	0.05	0.20	3600	165	0.83	0.75	8600	1959	1967 TCPL	42
27	0.05	0.20	3590	165	0.83	0.75	8680	1952	1967	43
							8990	1952	1967 TCPL	44
38	0.14	0.35	2800	180	0.84	0.71	7190	1967	1968	47
									1968	48
									1968	49
									1961 LOCAL UTILITY	52
8	0.24	0.40	970	80	0.89	0.59	2530	1949	1969 TCPL	55
		GIP BASED ON MATERIAL BALANCE					2570	1951	1969 TCPL	56
									1965	57
									1965 TCPL	58
22	0.14	0.65	1780	140	0.82	0.70	5050	1956	1969 NUL	61
									1969	62
14	0.08	0.35	1780	130	0.81	0.82	5090	1956	1966	63

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU.FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
PAKOWKI LAKE									
BOW ISLAND A	21	0.65	0.05	13	9	4	940	4	21480
BOW ISLAND (OTHER)	5	0.85	0.05	4		4	940	4	
MANNVILLE	1	0.90	0.05	1		1	1000	1	
PARKLAND									
RUNDLE	3	0.85	0.15	2**	2**		1010		
PARKLAND NORTH-EAST									
RUNDLE 29-15-26	15	0.85	0.15	11		11	1010	11	2130
RUNDLE (OTHER)	5	0.90	0.15	4		4	1010	4	
PELICAN									
WABISKAW	18	0.70	0.05	12		12	990	12	
WABISKAW ASSOC	3	0.65	0.05	2		2	990	2	
PEMBINA									
KEYSTONE BR A	36	0.80	0.05	24	3	21	1070*	22	5700
BELLY RIVER (OTHER)	30	0.80	0.05	23	1	22	1070*	24	
BELLY RIVER ASSOC	21	0.80	0.05	16		16	1070*	17	
BELLY RIVER SOLN	90	0.45	0.80	9	1	8	1070*	9	
CARDIUM SOLN	4100	0.36	0.40	880	162	718	1130*	811	
VIKING	11	0.80	0.05	8		8	1130*	9	
LOBSTICK GLAUC A	170	0.85	0.06	130	28	102	1130*	115	12600
LOBSTICK GLAUC B	93	0.85	0.06	74	8	66	1130*	75	5180
LOBSTICK GLAUC C & D	73	0.80	0.06	55	1	54	1130*	61	4970
MANNVILLE (OTHER)	19	0.75	0.05	14	4	10	1130*	11	
JURASSIC	18	0.85	0.05	15		15	1050*	16	
RUNDLE	13	0.85	0.10	10		10	1050*	11	
PENDANT D'OREILLE									
BOW ISLAND	200	0.85	0.05	160	101	59	940	55	86630
BOW ISLAND (OTHER)	4	0.85	0.05	3		3	940	3	
MANNVILLE A	47	0.90	0.05	40	20	20	1000	20	4480
MANNVILLE C	35	0.90	0.05	30	4	26	1000	26	2590
MANNVILLE (OTHER)	19	0.90	0.05	16	1	15	1000	15	
PENHOLD									
VIKING 33-36-28	14	0.90	0.05	12		12	1020	12	1650
PINCHER CREEK									
RUNDLE A	1800	0.40	0.25	540	258	282	1020*	288	14000
PINE CREEK									
WABAMUN	190	0.80	0.45	82	50	32	1050	34	9650
WABAMUN (OTHER)	30	0.85	0.45	14		14	1000	14	
D-3	770	0.50	0.35	250	150	100	1000	100	9480
PINE NORTH-WEST									
RUNDLE	8	0.85	0.10	6		6	1030	6	
D-3 A	350	0.65	0.25	170	16	154	980	151	4220
PLAIN									
VIKING	1	0.80	0.05	1		1	980	1	
SPARKY B	20	0.80	0.05	15		15	1000	15	
MANNVILLE (OTHER)	47	0.80	0.05	35		35	1000	35	
NISKU	3	0.75	0.05	2		2	990*	2	
CAMROSE	4	0.75	0.05	3		3	990*	3	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
3	0.21	0.30	790	75	0.91	0.59	2200	1955	1967 CMG	2
									1967	3
									1967	4
										5
										6
									1963 POOL ABANDONED	7
										8
										9
16	0.07	0.25	2830	145	0.83	0.66	6940	1953	1963 CONSIDERED BEYOND	10
									1956 ECONOMIC REACH	11
										12
										13
									1968	14
									1964	15
										16
										17
16	0.19	0.35	1020	100	0.88	0.60	3220	1956	1969 NUL	18
									1965 NUL	19
									1965	20
									1965 NUL	21
										22
							5080	1953	1967 NUL	23
									1956	24
25	0.14	0.40	1990	135	0.80	0.69	6000	1957	1968 A&S	25
23	0.16	0.30	1970	135	0.81	0.69	5640	1958	1968 NUL	26
24	0.15	0.35	1950	135	0.81	0.66	6080	1959	1968 A&S	27
										28
									1959 A&S	29
									1965	30
									1966 A&S	31
										32
										33
6	0.22	0.25	710	75	0.92	0.59	2030	1946	1968 CMG	34
									1967	35
20	0.21	0.35	1150	85	0.87	0.58	2740	1961	1968 CMG	36
25	0.22	0.35	1160	85	0.87	0.58	2690	1965	1968 CMG	37
										38
									1968 CMG	39
										40
										41
12	0.20	0.30	1710	145	0.89	0.69	5590	1958	1958 CONSIDERED BEYOND	42
									ECONOMIC REACH	43
										44
										45
310	0.04	0.20	4940	190	0.97	0.72	12500	1948	1961 TCPL	46
										47
										48
26	0.07	0.15	4500	210	0.82	0.83	10080	1956	1967 MAINTAINS PRESSURE	49
									1965 IN	50
122	0.07	0.15	4580	235	0.91	0.76	11020	1957	1969 WINDFALL D-3 A	51
										52
										53
									1968	54
133	0.08	0.10	4650	240	0.95	0.71	10670	1963	1969 MAINTAINS PRESSURE	55
									IN WINDFALL D-3 A	56
										57
										58
									1961	59
									1969	60
									1969	61
									1969	62
										63
									1969	64

CONFIDENTIAL

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

*** 1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED DEC. 31/69 BCF	7 REMAINING MARKETABLE GAS DEC. 31/69 BCF	8 GROSS HEATING VALUE BTU/CU.FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
PLOVER LAKE									
VIKING	18	0.90	0.05	15		15	1000	15	
POUCE COUPE									
PEACE RIVER A	150	0.70	0.05	100	91	9	1000	9	25700
PEACE RIVER (OTHER)	2	0.80	0.05	2		2	1000	2	
BLUESKY-GETHING	8	0.85	0.05	7		7	1000	7	
TRIASSIC	7	0.85	0.05	5		5	1060	5	
POUCE COUPE SOUTH									
DOE CREEK	5	0.60	0.05	3	2	1	1000	1	
PEACE RIVER A	34	0.70	0.03	23	19	4	1040	4	
PEACE RIVER B	44	0.30	0.02	31	31	¤ 1	1040	¤ 1	7160
PEACE RIVER (OTHER)	14	0.70	0.05	9		9	1040	9	
GETHING A	20	0.85	0.05	17	13	4	1000	4	
CADOMIN	13	0.85	0.05	10	2	8	1000	8	
TRIASSIC	18	0.80	0.05	14		14	1000	14	
PREVO									
MANNVILLE	5	0.85	0.10	4		4	1020	4	
PEKISKO A	44	0.85	0.10	34	9	25	1110*	28	2490
PRINCESS									
2WS A	60	0.80	0.05	45	6	39	970	38	33310
2WS (OTHER)	7	0.75	0.05	5		5	970*	5	
BOW ISLAND	5	0.75	0.05	4	1	3	1010	3	
BASAL COLORADO	16	0.75	0.05	12	4	8	1020*	8	
BASAL MANNVILLE A	18	0.90	0.05	15	5	10	1020*	10	1050
BASAL MANNVILLE C	38	0.85	0.05	31	1	30	1020*	31	2220
MANNVILLE (OTHER)	19	0.85	0.05	16	9	7	1020*	7	
MANN ASSOC	14	0.90	0.05	12	10	2	1020*	2	
JEFFERSON B	30	0.85	0.05	24	4	20	1030*	21	6940
JEFFERSON ASSOC	1	0.85	0.05	1		1	1030*	1	
PROVOST									
VIKING A & B	1050	0.88	0.02	900	296	604	1030	622	
VIKING (OTHER)	35	0.75	0.05	25		25	1030	26	
VIKING ASSOC	20	0.70	0.05	13		13	1030	13	
VIKING SOLN	5	0.33	0.10	2		2	1030	2	
MANNVILLE	32	0.85	0.05	25		25	1000	25	
QUIRK CREEK									
RUNDLE A	740	0.85	0.20	500		500	1110*	555	9900
RAINBOW									
SLAVE POINT	6	0.90	0.15	4		4	1100*	4	
SULPHUR POINT	38	0.85	0.15	28		28	1100*	31	
SULPHUR POINT ASSOC	3	0.85	0.15	2		2	1100*	2	
SULPHUR POINT SOLN	4	0.65	0.20	2		2	1100*	2	
MUSKEG	8	0.90	0.15	6		6	1120*	7	
MUSKEG SOLN	9	0.65	0.30	4		4	1150*	5	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1962 CONSIDERED BEYOND	2
									ECONOMIC REACH	3
										4
										5
25	0.18	0.30	620	95	0.93	0.57	2300	1922	1966 WESTCOAST	6
									1961	7
									1968	8
									1968	9
										10
										11
									1964 WESTCOAST AND PEACE	12
									RIVER TRANSMISSION	13
		GIP BASED ON MATERIAL BALANCE					3200	1956	1969 WESTCOAST AND PEACE	14
									RIVER TRANSMISSION	15
										16
23	0.17	0.30	800	105	0.91	0.57	3240	1953	1969 WESTCOAST AND PEACE	17
									RIVER TRANSMISSION	18
									1965	19
		GIP BASED ON MATERIAL BALANCE					4980	1958	1969 WESTCOAST AND PEACE	20
									RIVER TRANSMISSION	21
										22
									1968 WESTCOAST AND PEACE	23
									RIVER TRANSMISSION	24
									1965	25
										26
										27
									1966	28
25	0.10	0.20	2330	160	0.83	0.69	6580	1958	1966 TCPL	29
										30
										31
5	0.22	0.40	820	75	0.90	0.58	2190	1963	1967 TCPL	32
									1965	33
									1969 TCPL	34
									1966 TCPL	35
23	0.20	0.30	1550	85	0.82	0.61	3170	1940		36
23	0.20	0.30	1550	85	0.83	0.64	3230	1940	1966 TCPL	37
									1965 TCPL	38
									1967 TCPL	39
									1966 TCPL	40
14	0.08	0.25	1590	100	0.82	0.82	3190	1940	1965 TCPL	41
										42
									1965	43
										44
										45
		GIP BASED ON MATERIAL BALANCE					2510	1946	1968 TCPL AND LOCAL	46
									UTILITY	47
									1968	48
									1969	49
										50
									1969	51
									1961 TCPL	52
										53
										54
143	0.08	0.15	2270	120	0.75	0.75	6160	1967	1969	55
										56
										57
									1967 CONSIDERED BEYOND	58
									1967 ECONOMIC REACH	59
									1967	60
									1969	61
										62
									1967	63
									1969	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

***	1	2	3	4	5	6	7	8	9	10
	POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
1	RAINBOW (CONTINUED)									
2	KEG RIVER Q	18	0.85	0.10	14		14	1150*	16	160
3	KEG RIVER FFF	19	0.90	0.10	16	1	15	1150*	17	160
4	KEG RIVER (OTHER)	17	0.85	0.15	12		12	1150*	14	
5										
6	KEG RIVER A ASSOC	33	0.85	0.15	24	-11	35	1200*	42	340
7	KEG RIVER F ASSOC	74	0.85	0.90	57		57	1200*	68	2260
8	KR ASSOC (OTHER)	20	0.85	0.10	15		15	1200*	18	
9	KEG RIVER A SOLN	72	0.75	0.20	43	4	39	1260*	49	
10	KEG RIVER B SOLN	91	0.45	0.20	33	2	31	1260*	39	
11										
12	KEG RIVER F SOLN	150	0.75	0.15	97	3	94	1260*	118	
13	KEG RIVER O SOLN	30	0.50	0.25	11		11	1260*	14	
14	KEG RIVER AA SOLN	52	0.40	0.20	17		17	1260*	21	
15	KEG RIVER EEE SOLN	19	0.70	0.25	10		10	1260*	13	
16	KEG R SOLN (OTHER)	170	0.75	0.25	91	1	90	1260*	113	
17										
18	RAINBOW SOUTH									
19	WINTERBURN	2	0.90	0.05	2		2	1060*	2	
20	SULPHUR POINT	33	0.85	0.10	24		24	1100*	26	
21	MUSKEG	15	0.85	0.20	11		11	1100*	12	
22	MUSKEG SOLN	4	0.65	0.25	2		2	1150*	2	
23										
24	KEG RIVER	7	0.85	0.15	5		5	1150*	6	
25	KEG RIVER ASSOC	18	0.85	0.15	13		13	1150*	15	
26	KEG RIVER A SOLN	34	0.75	0.25	19		19	1200*	23	
27	KEG RIVER B SOLN	37	0.75	0.15	24		24	1200*	29	
28	KEG RIVER E SOLN	57	0.75	0.25	32		32	1200*	38	
29										
30	KEG RIVER G SOLN	24	0.75	0.25	13		13	1200*	16	
31	KEG R SOLN (OTHER)	20	0.75	0.25	11		11	1200*	13	
32										
33	REDLAND									
34	BELLY RIVER	1	0.65	0.05	1		1	1000	1	
35	VIKING	3	0.80	0.05	2		2	1000	2	
36	UPPER MANNVILLE A	31	0.85	0.04	25	5	20	1070	21	
37	MANNVILLE	8	0.90	0.05	7		7	1070	7	
38										
39	REDWATER									
40	VIKING	26	0.75	0.05	19	1	18	1040	19	
41										
42	MANNVILLE	1	0.80	0.05	1	1	¤ 1	1050	¤ 1	
43										
44										
45	D-1	4	0.85	0.05	3	2	1	1070	1	
46										
47	D-3 SOLN	240	0.60	0.65	49	14	35	1220*	43	
48										
49										
50	RED WILLOW									
51	VIKING A	16	0.75	0.05	12		12	1020	12	6060
52	VIKING (OTHER)	2	0.80	0.05	2		2	1020	2	
53	MANNVILLE	17	0.80	0.05	13		13	1100	14	
54										
55	RETLAW									
56	BOW ISLAND	8	0.75	0.05	6	1	5	950	5	
57	BASAL COLORADO	8	0.75	0.05	6		6	1020	6	
58	MANNVILLE B & D	27	0.90	0.10	22	7	15	1000	15	3990
59	MANNVILLE J	21	0.90	0.05	18	1	17	1000	17	1250
60										
61	MANNVILLE K	14	0.90	0.15	11		11	1000	11	1250
62	MANNVILLE (OTHER)	45	0.85	0.10	33		33	1000	33	
63	RUNDLE	2	0.85	0.10	1		1	1010	1	
64	RUNDLE ASSOC	2	0.90	0.10	2		2	1010	2	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F)

	11	12	13	14	15	16	17	18	19	20
	AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
1										
2	248	0.07	0.10	2400	630	0.85	0.70	5743	1966	1968
3	396	0.05	0.20	2570	600	0.80	0.70	6050	1966	1968 INJ INTO GAS CAP
4										1967
5										
6	171	0.11	0.06	2570	655	0.82	0.78	6015	1965	1969
7	79	0.07	0.15	2480	180	0.70	0.70	5870	1966	1967
8										1967
9								6390	1965	1969 INJ INTO GAS CAP
10								5970	1965	1967 INJ INTO GAS CAP
11										
12								6090	1966	1967 INJ INTO GAS CAP
13								6050	1966	1969
14								5530	1967	1969
15								6090	1968	1968
16										1969 INJ INTO GAS CAP
17										
18										
19										1967 CONSIDERED BEYOND
20										1967 ECONOMIC REACH
21										1967
22										1969
23										
24										1967
25										1967
26								6370	1965	1967
27								6460	1966	1969
28								6440	1966	1969
29										
30								6390	1967	1968
31										1969
32										
33										
34										1966
35										1961
36			GIP BASED ON MATERIAL BALANCE					4870	1961	1969 CWNG
37										1961
38										
39										
40										1965 LOCAL UTILITY AND
41										CIGOL
42										1960 LOCAL UTILITY AND
43										CIGOL
44										
45										1967 LOCAL UTILITY AND
46										CIGOL
47								3210	1948	1965 LOCAL UTILITY AND
48										CIGOL
49										
50										
51	6	0.23	0.35	930	105	0.90	0.60	3210	1955	1969 CONSIDERED BEYOND
52										1962 ECONOMIC REACH
53										1969
54										
55										
56										1968 TCPL
57										1965
58	7	0.22	0.30	1720	95	0.79	0.71	3570	1959	1968 TCPL
59	23	0.21	0.40	1700	95	0.81	0.71	3110	1966	1967 TCPL
60										
61	8	0.29	0.15	1650	85	0.79	0.71	3550	1954	1969
62										1968
63										1966
64										1966

TABLE A-1 · CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
RICH									
LOWER MANNVILLE A	16	0.85	0.10	12	2	10	1100	11	3810
RICHDALE									
VIKING A,B,& C	19	0.85	0.05	16	1	15	1010	15	6650
MANNVILLE	11	0.75	0.05	9		9	1050	9	
RICINUS									
CARDIUM A ASSOC	200	0.85	0.15	140		140	1000	140	4000
D-3 A	150	0.85	0.35	80		80	1100	88	680
RICINUS WEST									
D-3 A	410	0.80	0.45	180		180	1100	198	
ROCHESTER									
VIKING	4	0.80	0.05	3		3	1000	3	
MANNVILLE	25	0.75	0.05	18		18	1000	18	
WABAMUN	6	0.90	0.05	5		5	1070	5	
ROWLEY									
BELLY RIVER	6	0.80	0.05	4		4	1000	4	
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	12	0.85	0.05	10		10	1070	11	
MANNVILLE ASSOC	5	0.85	0.05	4		4	1070	4	
PEKISKO A ASSOC	47	0.90	0.10	38**					6780
PEKISKO A SOLN	8	0.65	0.25	4**	6**	36	1100*	40	
RYCROFT									
BLUESKY	7	0.80	0.05	5	3	2	1040	2	
GETHING	13	0.90	0.05	11	1	10	1040	10	
SADDLE HILLS									
CADOTTE D	37	0.70	0.05	25		25	1020	26	5380
PEACE RIVER (OTHER)	11	0.70	0.05	7		7	1020	7	
GETHING	5	0.80	0.05	4		4	980	4	
BELLOY A	22	0.80	0.15	15		15	1030	15	1050
ST. ALBERT-BIG LAKE									
VIKING	1	0.80	0.05	1		1	1070*	1	
VIKING ASSOC	2	0.80	0.05	2		2	1070*	2	
OSTRACOD A	98	0.85	0.05	80	67	13	1070*	14	
BASAL QUARTZ B	26	0.85	0.05	21		21	1070*	22	1060
MANNVILLE (OTHER)	10	0.85	0.05	8		8	1070*	9	
ST. PAUL									
MANNVILLE	5	0.75	0.10	4	4	¤ 1	1000	¤ 1	
SAMSON									
BLAIRMORE	8	0.85	0.05	7	1	6	1070*	6	
BLAIRMORE ASSOC	9	0.80	0.05	7**					
BLAIRMORE SOLN	2	0.65	0.05	1**	6**	2	1070*	2	
SARCEE									
RUNDLE A	210	0.85	0.15	150	49	101	1050*	106	3100
SARCEE WEST									
KOOTENAY 17-23-4	13	0.80	0.05	10		10	1020	10	500
SAVANNA CREEK									
RUNDLE A	230	0.67	0.30	110	34	76	1020	78	5450

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
13	0.12	0.30	1270	135	0.87	0.65	4800	1953	1961 TCPL
8	0.20	0.40	1080	90	0.87	0.60	3030	1955	1968 TCPL
									1968
32	0.14	0.10	3940	155	0.83	0.83	8750	1969	1969
186	0.10	0.10	5870	235	0.97	0.77	13580	1968	1969
		CONFIDENTIAL							1969
									1953 CONSIDERED BEYOND
									1953 ECONOMIC REACH
									1953
									1964
									1966
									1964
									1965
22	0.08	0.20	1500	120	0.82	0.71	4410	1960	1965
									1967 TCPL
									1961 LOCAL UTILITY
									1961 LOCAL UTILITY
17	0.21	0.30	930	115	0.92	0.57	3640	1957	1965
									1965
									1965
35	0.10	0.25	2600	155	0.82	0.65	6970	1957	1965
									1965
									1957
		GIP BASED ON MATERIAL BALANCE					3710	1952	1962 CIGOL
33	0.20	0.25	1360	120	0.85	0.67	3800	1952	1964
									1964
									1966 LOCAL UTILITY
									1968 NUL
									1965
									1965 NUL
103	0.08	0.20	3790	180	0.88	0.72	9750	1954	1964 CWNG
45	0.10	0.35	3650	225	0.95	0.67	11030	1957	1958 CONSIDERED BEYOND ECONOMIC REACH
219	0.03	0.15	2770	135	0.78	0.66	8350	1954	1969 WESTCOAST

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
SEDALIA									
VIKING A	110	0.50	0.08	50	8	42	1010*	42	65810
VIKING (OTHER)	4	0.80	0.05	3		3	1010	3	
MANNVILLE	5	0.85	0.05	4		4	1010	4	
SEDGEWICK									
VIKING	3	0.75	0.05	2		2	1000	2	
BASAL MANNVILLE A	19	0.85	0.05	16		16	990	16	2310
MANNVILLE (OTHER)	10	0.85	0.05	8		8	990	8	
SEIU LAKE									
VIKING	1	0.75	0.05	1		1	1000	1	
MANNVILLE	14	0.85	0.05	11	1	10	1000	10	
SEPTEMBER LAKE									
MANNVILLE	12	0.75	0.05	8		8	1030	8	
MANNVILLE ASSOC	1	0.75	0.05	1		1	1030	1	
WABAMUN	2	0.75	0.05	1		1	940	1	
SEXSMITH									
DUNVEGAN	8	0.80	0.05	6	1	5	1000	5	
SIBBALD									
VIKING A	28	0.80	0.05	21	15	6	990	6	9870
VIKING (OTHER)	8	0.80	0.05	6		6	990	6	
BASAL COLORADO A	13	0.80	0.05	10		10	990	10	4210
BANFF	1	0.80	0.05	1		1	1050	1	
SIMONETTE									
PEACE RIVER	9	0.90	0.05	7		7	1050	7	
CADOMIN A	13	0.85	0.05	10		10	1060	11	1500
WABAMUN A	34	0.85	0.35	19		19	1070	20	250
WABAMUN (OTHER)	14	0.85	0.35	8		8	1070	9	
D-3 SOLN	270	0.55	0.40	89	3	86	1020	88	
SMITH COULEE									
BOW ISLAND A	32	0.85	0.05	26	24	2	930	2	
STANDARD									
VIKING A	26	0.80	0.05	20		20	1000	20	5550
STEEP CREEK									
GETHING	6	0.85	0.05	5		5	1020	5	
TRIASSIC	9	0.85	0.10	7		7	1030	7	
PERMO-PENN 26-66-7	17	0.90	0.20	12		12	1030	12	1100
STETTLER									
VIKING	3	0.80	0.05	2		2	1020	2	
MANNVILLE	2	0.80	0.05	2		2	1090	2	
D-2 SOLN	21	0.30	0.90	1		1	1130	1	
D-3 SOLN	14	0.55	0.95	1		1	1140	1	
STOLBERG									
RUNDLE A	86	0.90	0.10	70		70	1040	73	1480
STRACHAN									
D-3 A	1770	0.85	0.20	1200		1200	1100	1320	4970
STRATHMORE									
BELLY RIVER	14	0.80	0.05	11	4	7	1000	7	
VIKING	9	0.80	0.05	7		7	1000	7	
RUNDLE	2	0.80	0.05	1		1	1000	1	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
6	0.26	0.35	940	85	0.88	0.57	2650	1950	1969 TCPL	2
									1968	3
									1968 TCPL	4
										5
										6
									1956	7
11	0.30	0.20	980	95	0.86	0.64	2940	1954	1968	8
									1956	9
										10
										11
									1966	12
									1963 TCPL	13
										14
										15
									1966 CONSIDERED BEYOND	16
									1966 ECONOMIC REACH	17
									1966	18
										19
										20
									1969 LOCAL UTILITY	21
										22
										23
6	0.22	0.30	1000	90	0.89	0.58	2530	1951	1966 TCPL	24
									1960	25
8	0.15	0.30	1110	90	0.87	0.61	2700	1953	1960	26
									1966	27
										28
										29
									1957	30
17	0.09	0.35	2970	165	0.85	0.66	8110	1960	1968	31
154	0.08	0.15	4950	220	0.87	0.81	11240	1959	1966 CUL AND A&S	32
									1967	33
										34
							11580	1958	1966 CUL AND A&S	35
										36
										37
		GIP BASED ON MATERIAL BALANCE					2050	1948	1967 CMG	38
										39
										40
8	0.20	0.30	1290	85	0.84	0.63	4180	1956	1963 TCPL	41
										42
										43
									1961 CONSIDERED BEYOND	44
									1961 ECONOMIC REACH	45
35	0.06	0.30	4350	240	0.91	0.66	10470	1956	1961	46
										47
										48
									1963 CWNG	49
									1969	50
									1966 CWNG	51
									1966 CWNG	52
										53
										54
122	0.05	0.20	5100	200	0.99	0.64	12730	1957	1958	55
										56
										57
363	0.08	0.10	7150	250	1.14	0.74	13520	1967	1969	58
										59
										60
									1963 CWNG	61
									1963	62
									1963	63

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
STROME									
MANNVILLE	4	0.85	0.10	3		3	1030	3	
STURGEON LAKE									
GETHING	13	0.85	0.05	10		10	1000	10	
GILWOOD	1	0.85	0.15	1		1	1000	1	
STURGEON LAKE SOUTH									
GETHING 19-69-25	21	0.85	0.10	16		16	1000	16	1100
GETHING (OTHER)	18	0.85	0.05	14		14	1000	14	
TRIASSIC ASSOC	3	0.85	0.10	2		2	1180	2	
TRIASSIC SOLN	22	0.65	0.70	4		4	1180	5	
PERMO-PENN	11	0.85	0.05	9		9	1030	9	
D-1	4	0.90	0.20	3	1	2	1070	2	
D-3 ASSOC	8	0.90	0.25	5		5	1080	5	
D-3 SOLN	270	0.55	0.45	83	17	66	1080	71	
D-3 ASSOC (OTHER)	2	0.90	0.25	1		1	1080	1	
SUNDRE									
MANNVILLE	6	0.85	0.10	4		4	1020	4	
MANNVILLE ASSOC	10	0.90	0.10	8		8	1020	8	
RUNDLE A ASSOC	21	0.85	0.15	15		15	1060*	16	1660
RUNDLE A SOLN	59	0.40	0.50	12		12	1060*	13	
RUNDLE SOLN (OTHER)	13	0.60	0.50	4		4	1060*	4	
SUNNYNOOK									
VIKING	1	0.75	0.05	1		1	1020	1	
MANNVILLE	16	0.85	0.05	13	1	12	1020	12	
SWALWELL									
VIKING	7	0.80	0.05	5		5	1000	5	
PEKISKO A ASSOC	43	0.85	0.05	35		35	1100	39	4000
SWAN HILLS									
GETHING	2	0.90	0.05	1		1	1050	1	
BH LK A & B SOLN	1020	0.45	0.35	300	26	274	1200*	329	
SWAN HILLS SOUTH									
BH LK A & B SOLN	570	0.45	0.30	180	19	161	1120*	180	
SYLVAN LAKE									
VIKING	4	0.85	0.05	3		3	1010*	3	
GLAUCONITIC A	210	0.85	0.10	170	40	130	1100*	143	9290
OSTRACOD B	29	0.85	0.10	22	2	20	1100*	22	2230
LOWER MANNVILLE A	35	0.85	0.10	27	7	20	1100*	22	2830
LOWER MANNVILLE C	21	0.85	0.09	16	11	5	1100*	6	2260
LOWER MANNVILLE D	28	0.85	0.06	23	3	20	1100*	22	2620
MANNVILLE (OTHER)	38	0.85	0.10	28	1	27	1100*	30	
MANNVILLE ASSOC	3	0.80	0.10	2		2	1100*	2	
JURASSIC L	14	0.85	0.15	10		10	1020*	10	1130
JURASSIC (OTHER)	14	0.85	0.10	11	1	10	1020*	10	
JURASSIC A ASSOC	46	0.80	0.10	33		33	1020*	34	3010
JUR ASSOC (OTHER)	3	0.85	0.10	2		2	1020*	2	
JURASSIC SOLN	23	0.60	0.45	8		8	1100*	9	
ELKTON-SHUNDA A	24	0.85	0.10	18	8	10	1100*	11	3380
SHUNDA B	22	0.85	0.10	16		16	1100*	18	1790
RUNDLE (OTHER)	30	0.85	0.10	22		22	1100*	24	
PEKISKO B ASSOC	18	0.80	0.15	13		13	1100*	14	1410
RUNDLE ASSOC (OTHER)	7	0.80	0.15	5		5	1100*	6	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1969 LOCAL UTILITY	2
										3
										4
									1967 CONSIDERED BEYOND	5
									1967 ECONOMIC REACH	6
										7
										8
34	0.15	0.30	1700	115	0.86	0.61	5200	1954	1967	9
									1967	10
									1967	11
									1969 A&S AND CUL	12
										13
									1968	14
									1967 CUL	15
									1961	16
							8850	1953	1965 A&S AND CUL	17
									1964	18
										19
										20
									1964 TCPL	21
									1966	22
16	0.10	0.20	3670	200	0.90	0.65	9050	1955	1964	23
							9050	1955	1965 A&S	24
										25
									1965 A&S	26
										27
										28
									1966	29
									1966 TCPL	30
										31
										32
									1966	33
32	0.08	0.25	1790	145	0.83	0.69	5300	1963	1966	34
										35
										36
									1962	37
							8300	1957	1969 NUL	38
										39
										40
							7450	1959	1966 NUL	41
										42
										43
									1969	44
31	0.13	0.30	2420	145	0.79	0.73	6950	1953	1969 TCPL	45
13	0.17	0.30	2950	160	0.83	0.68	7790	1963	1969 TCPL	46
18	0.13	0.30	2480	150	0.81	0.70	7150	1955	1969 TCPL	47
										48
13	0.13	0.30	2450	150	0.80	0.71	7140	1953	1969 TCPL	49
16	0.13	0.30	2410	145	0.81	0.73	6890	1953	1969 TCPL	50
									1969 TCPL	51
									1969	52
16	0.14	0.30	2440	150	0.80	0.70	7250	1962	1969	53
										54
									1969 TCPL	55
21	0.14	0.30	2500	160	0.83	0.69	7410	1962	1969	56
									1969	57
									1965	58
17	0.07	0.25	2430	150	0.80	0.70	7150	1955	1969 TCPL	59
										60
23	0.10	0.25	2450	150	0.81	0.70	7180	1953	1969	61
									1969	62
16	0.14	0.25	2460	150	0.80	0.71	7260	1962	1969	63
									1969	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVI

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
SYLVAN LAKE (CONTINUED)									
PEKISKO B SOLN	26	0.60	0.35	10		10	1200*	12	
RUNDLE SOLN (OTHER)	16	0.60	0.35	6		6	1200*	7	
D-3 A ASSOC	40	0.80	0.10	29**					1800
D-3 A SOLN	15	0.65	0.45	5**	4**	30	1020*	31	
TABER SOUTH									
BOW ISLAND A	17	0.70	0.05	11		11	1000	11	12410
BOW ISLAND (OTHER)	11	0.80	0.05	8		8	1000	8	
TANGENT									
PEACE RIVER	12	0.75	0.05	6		6	1010	6	
GETHING	42	0.85	0.05	34		34	1000	34	
TRIASSIC	25	0.85	0.05	20		20	1180	24	
TEHZE									
SULPHUR POINT SOLN	1	0.65	0.25	1		1	1100*	1	
MUSKEG SOLN	3	0.65	0.25	2		2	1150*	2	
KEG RIVER SOLN	16	0.70	0.25	8		8	1260*	10	
TELFORDVILLE									
MISSISSIPPIAN	11	0.85	0.10	9		9	1110	10	
WABAMUN	7	0.85	0.15	4		4	1090	4	
THORHILD									
MANNVILLE A	12	0.85	0.05	10		10	1000	10	2550
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000	1	
THREE HILLS CREEK									
BELLY RIVER	8	0.85	0.05	7		7	970	7	
VIKING	8	0.80	0.05	6		6	1000	6	
PEKISKO	190	0.85	0.05	150	25	125	1120*	140	43770
LEDUC	11	0.75	0.15	7		7	1100	8	
TROCHU									
MANNVILLE	14	0.75	0.10	10		10	1030	10	
TURIN									
BOW ISLAND	14	0.80	0.05	10		10	970	10	
MANNVILLE	17	0.90	0.15	13		13	1020	13	
MANNVILLE ASSOC	10	0.85	0.15	7		7	1020	7	
TURNER VALLEY									
RUNDLE ASSOC	1570	0.90	0.70	410	299	111	1110*	123	
RUNDLE SOLN	1400	0.55	0.55	350	287	63	1110*	70	
TWEEDIE									
VIKING	13	0.80	0.05	10	2	8	1000	8	
GRAND RAPIDS A	15	0.80	0.05	11	2	9	1040	9	9290
GLAUC A & MCMURRAY A	57	0.80	0.05	43	4	39	1040	41	22400
MANNVILLE (OTHER)	7	0.80	0.05	5	1	4	1040	4	
TWINING NORTH									
MANNVILLE	6	0.80	0.05	5		5	1100	6	
RUNDLE	1	0.80	0.05	1		1	1110	1	
RUNDLE ASSOC	37	0.80	0.05	28		28	1110	31	4340
RUNDLE ASSOC (OTHER)	1	0.80	0.05	1		1	1110	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
							7320	1962	1969	2
									1965	4
41	0.07	0.15	3470	210	0.90	0.70	9400	1961	1969	5
									1964 TCPL	6
6	0.20	0.30	540	80	0.94	0.60	2300	1963	1965 CONSIDERED BEYOND	9
									1961 ECONOMIC REACH	10
									1968	13
									1968	14
									1968	15
									1969 CONSIDERED BEYOND	18
									1968 ECONOMIC REACH	19
									1969	20
									1957	23
									1966	24
12	0.25	0.30	740	85	0.91	0.60	2570	1963	1966 LOCAL UTILITY	27
									1964	28
									1963	31
									1963	32
27	0.05	0.35	1720	150	0.85	0.70	5770	1953	1968 TCPL	33
									1963	34
									1968	37
									1968	40
									1968	41
									1968	42
							6000	1928	1953 CWNG AND LOCAL	45
							8390	1928	1953 UTILITY	46
									1968 GREAT CANADIAN OIL	49
									SANDS LIMITED	50
6	0.38	0.30	320	55	0.95	0.56	900	1961	1969 GREAT CANADIAN	51
									OIL SANDS LIMITED	52
16	0.27	0.50	360	60	0.95	0.57	1410	1961	1969 GREAT CANADIAN	54
									OIL SANDS LIMITED	55
									1968 GREAT CANADIAN OIL	56
									SANDS LIMITED	57
									1964	60
									1964	61
36	0.07	0.30	1660	145	0.85	0.68	5370	1961	1964	62
									1964	63

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
TWINING NORTH (CONTINUED)									
RUNDLE SOLN	15	0.60	0.15	8		8	1110	9	
TWO CREEK									
TRIASSIC 11-63-16	12	0.90	0.05	10		10	1090	11	1100
UKALTA									
WABAMUN-GRAMINIA A	42	0.75	0.05	30		30	1100*	33	
USONA									
MANNVILLE 11-45-27	12	0.90	0.05	10		10	1110	11	470
VERGER									
BOW ISLAND	6	0.80	0.05	4		4	1100	4	
BASAL COLORADO A	12	0.85	0.05	10	3	7	1010	7	10130
BSL COLORADO (OTHER)	17	0.80	0.05	13		13	1010	13	
MANNVILLE	19	0.85	0.10	15	3	12	1050	13	
RUNDLE	2	0.85	0.05	2		2	1070	2	
VIKING-KINSELLA									
VIKING	960	0.85	0.05	770	425	345	1000	345	40800
WAINWRIGHT	41	0.80	0.05	31	4	27	1000	27	6750
MANNVILLE (OTHER)	40	0.80	0.05	30	15	15	1000	15	
D-2	9	0.75	0.05	7	5	2	990*	2	
CAMROSE	8	0.80	0.05	7	1	6	990*	6	
VIRGINIA HILLS									
MANNVILLE	9	0.90	0.05	8		8	1040	8	
BELLOY A ASSOC	35	0.85	0.10	29		29	1060	31	4730
BEAVERHILL LAKE SOLN	220	0.40	0.40	54	7	47	1070*	50	
SLAVE POINT	4	0.80	0.20	2		2	1070	2	
VIRGO									
SLAVE POINT	10	0.90	0.10	8		8	1050*	8	
SULPHUR POINT	21	0.90	0.15	16		16	1050*	17	
MUSKEG	6	0.90	0.20	4		4	1050*	4	
MUSKEG ASSOC	7	0.85	0.15	5		5	1050*	5	
MUSKEG SOLN	3	0.60	0.25	1		1	1100*	1	
KEG RIVER HH ASSOC	13	0.90	0.20	10		10	1150*	12	160
KEG R ASSOC (OTHER)	37	0.90	0.20	27		27	1150*	31	
KEG RIVER SOLN	50	0.70	0.25	26		26	1200*	31	
VULCAN									
U MANN B &BSL MANN A	17	0.85	0.15	13	1	12	1050	13	2320
MANNVILLE (OTHER)	3	0.85	0.15	2	1	1	1050	1	
TURNER VALLEY A	19	0.80	0.20	13	1	12	1050	13	2440
RUNDLE (OTHER)	4	0.80	0.20	2		2	1050	2	
WAINWRIGHT									
VIKING	5	0.80	0.05	4		4	980	4	
MANNVILLE	18	0.85	0.05	14		14	940	13	
MANNVILLE ASSOC	8	0.75	0.05	5		5	940	5	
WASKAHIGAN									
CARDIUM	4	0.80	0.05	3		3	1060	3	
DUNVEGAN A	125	0.80	0.05	90		90	1110	100	26980
PEACE RIVER	5	0.85	0.05	4		4	1070	4	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1965
12	0.20	0.30	2200	170	0.88	0.66	6590	1956	1956 CONSIDERED BEYOND ECONOMIC REACH
		CONFIDENTIAL							1969
32	0.22	0.30	1660	140	0.84	0.71	5110	1954	1955 CONSIDERED BEYOND ECONOMIC REACH
2	0.21	0.40	1280	90	0.86	0.60	3060	1959	1964 TCPL
									1969 TCPL
									1969 TCPL
									1968 TCPL
									1964 TCPL
5	0.23	0.20	810	75	0.90	0.60	2080	1914	1966 NUL AND LOCAL UTILITY
13	0.26	0.25	740	85	0.91	0.59	2330	1951	1966 NUL
									1966 NUL
									1966 NUL
									1961 NUL
									1962
13	0.15	0.30	1950	155	0.86	0.69	6150	1961	1969
							9290	1957	1966 NUL
									1962
									1968 CONSIDERED BEYOND
									1968 ECONOMIC REACH
									1968
									1968
									1969
155	0.08	0.10	2240	155	0.80	0.79	5040	1968	1968
									1969
10	0.15	0.35	2320	125	0.85	0.76	5880	1956	1968 TCPL
									1968 TCPL
13	0.10	0.40	2440	145	0.82	0.76	5940	1960	1966 TCPL
									1966
									1959 LOCAL UTILITY
									1960 LOCAL UTILITY
									1968
									1967
12	0.16	0.45	1490	145	0.85	0.67	5080	1959	1969
									1967

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROV

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WATERTON									
RUNDLE A	54	0.80	0.30	32	5	27	1040*	28	
RUNDLE C	350	0.75	0.45	150	11	139	1040*	145	13390
RUNDLE D & E	470	0.80	0.50	190	48	142	1040*	148	
RUNDLE (OTHER)	19	0.80	0.30	11		11	1040*	11	
RUNDLE-WABAMUN A	3080	0.85	0.35	1700	168	1532	1020	1563	
WABAMUN B	36	0.80	0.20	25	11	14	1020	14	
WABAMUN 31-6-3	40	0.85	0.15	29		29	1020	30	2000
WATTS									
VIKING	5	0.85	0.07	4	2	2	1030*	2	
MISSISSIPPIAN	1	0.80	0.05	1		1	1070	1	
WAYNE-ROSEDALE									
BELLY RIVER	8	0.80	0.05	6	1	5	1000	5	
VIKING A	170	0.80	0.05	130	31	99	1090*	108	49900
VIKING B	24	0.80	0.05	18	5	13	1090*	14	9940
VIKING (OTHER)	26	0.80	0.05	20	1	19	1090*	21	
GLAUCONITIC A	170	0.85	0.07	140	31	109	1120	122	19440
MANNVILLE (OTHER)	90	0.85	0.05	71	12	59	1120	66	
MANNVILLE ASSOC	6	0.85	0.05	5	2	3	1120	3	
WEST DRUMHELLER									
MANNVILLE	4	0.85	0.05	3		3	1100	3	
RUNDLE	1	0.80	0.05	1		1	1040	1	
D-2 ASSOC	5	0.90	0.15	4		4	1090	4	
WESTEROSE									
VIKING	3	0.80	0.05	2		2	1000	2	
MANNVILLE	7	0.80	0.05	5		5	1020	5	
NISKU	2	0.90	0.05	1		1	1050	1	
D-3 ASSOC	130	0.90	0.20	90	-7	97	1050*	102	1220
D-3 SOLN	150	0.70	0.20	83	11	72	1050*	76	
WESTEROSE SOUTH									
WABAMUN	8	0.90	0.25	6		6	1090	7	
D-3 A	1850	0.90	0.20	1350	445	905	1060*	959	11790
WESTLOCK									
VIKING	320	0.80	0.05	250	76	174	1060	184	75270
VIKING (OTHER)	8	0.80	0.05	6		6	1060	6	
MANNVILLE	4	0.85	0.05	3		3	1100*	3	
WEST PRAIRIE									
CADOTTE 18-72-17	17	0.90	0.05	15		15	1040	16	1100
BLUESKY	6	0.90	0.05	5		5	990	5	
WHISKEY									
RUNDLE A	160	0.85	0.25	100		100	1110*	111	2130
WHITECOURT									
BELLY RIVER	2	0.85	0.05	1		1	1000	1	
VIKING	1	0.75	0.05	1		1	1050	1	
MANNVILLE	14	0.80	0.10	10		10	1050	11	
JURASSIC E	55	0.85	0.10	42		42	1070	45	5130
JURASSIC (OTHER)	26	0.80	0.10	18		18	1070	19	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
		GIP BASED ON MATERIAL BALANCE					9406	1960	1968 A&S	2
56	0.05	0.25	5200	190	1.00	0.94	11600	1957	1968 A&S	3
		GIP BASED ON MATERIAL BALANCE					10700	1957	1968 A&S	4
									1969 A&S	5
										6
		GIP BASED ON MATERIAL BALANCE					10350	1959	1968 A&S	7
		GIP BASED ON MATERIAL BALANCE					13400	1958	1968 A&S	8
58	0.05	0.20	4020	205	0.91	0.66	12170	1964	1966	9
										10
										11
									1969 LOCAL UTILITY	12
									1955	13
										14
										15
									1969 CWNG	16
6	0.20	0.30	1170	100	0.85	0.64	3890	1953	1969 TCPL AND CWNG	17
9	0.17	0.60	1170	100	0.85	0.64	3870	1954	1969 TCPL	18
									1969 TCPL, CWNG AND LOCAL	19
									UTILITY	20
										21
13	0.20	0.30	1460	105	0.81	0.67	4370	1953	1969 TCPL, CWNG AND LOCAL	22
									UTILITY	23
									1969 TCPL, CWNG AND LOCAL	24
									UTILITY	25
									1969 TCPL	26
										27
										28
									1954	29
									1956	30
									1968	31
										32
										33
									1961	34
									1953	35
									1959	36
200	0.08	0.15	2520	180	0.83	0.71	6990	1952	1959	37
										38
							7230	1952	1966 TCPL	39
										40
										41
									1961	42
249	0.09	0.10	2750	180	0.81	0.81	7640	1953	1969 TCPL	43
										44
										45
13	0.19	0.35	840	95	0.90	0.58	2600	1949	1964 CIGOL & LOCAL	46
									UTILITY	47
									1964	48
									1962	49
										50
										51
35	0.20	0.30	990	85	0.87	0.68	2580	1956	1956 CONSIDERED BEYOND	52
									1956 ECONOMIC REACH	53
										54
										55
136	0.06	0.25	3820	150	0.83	0.72	11820	1968	1969	56
										57
										58
									1963	59
									1958	60
									1963	61
23	0.18	0.50	1850	140	0.84	0.64	5070	1962	1969	62
										63
									1968 TCPL	64

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WHITECOURT (CONTINUED)									
PEKISKO C	13	0.85	0.10	10		10	1130	11	830
RUNDLE (OTHER)	35	0.85	0.10	26		26	1130	29	
WHITELAW									
BLUESKY (OTHER)	2	0.80	0.05	1		1	1020	1	
BLUESKY A & GETH A	14	0.85	0.05	12	5	7	1020	7	2600
GETHING B	13	0.85	0.05	11	1	10	1020	10	3720
TRIASSIC A	21	0.85	0.05	16		16	1090	17	5680
TRIASSIC (OTHER)	10	0.90	0.05	9		9	1090	10	
WILDCAT HILLS									
RUNDLE A	1050	0.80	0.17	700	162	538	1050*	565	
WILDHORSE CREEK									
RUNDLE A	160	0.85	0.20	110		110	1010	111	1960
WILDMERE									
MANNVILLE	37	0.80	0.05	28	10	18	960*	17	
WILDUNN CREEK									
VIKING A	19	0.60	0.05	11		11	1010	11	8810
VIKING B	16	0.70	0.05	11	4	7	1010	7	4080
WILLESDEN GREEN									
BELLY RIVER E	34	0.85	0.10	26		26	1000	26	3790
BELLY RIVER (OTHER)	23	0.80	0.05	17		17	1000	17	
CARDIUM	6	0.80	0.05	4		4	1040*	4	
CARDIUM A ASSOC	21	0.85	0.10	16**					6390
CARDIUM A SOLN	460	0.40	0.60	74**	8**	82	1040*	85	
MANNVILLE	19	0.85	0.15	14		14	1100	15	
MANNVILLE ASSOC	10	0.85	0.10	7		7	1100	8	
JURASSIC	4	0.75	0.05	3		3	1080	3	
RUNDLE	3	0.80	0.05	2		2	1100	2	
WILLINGDON									
VIKING	3	0.75	0.05	2		2	980	2	
MANNVILLE	16	0.75	0.05	12	4	8	990	8	
D-3	12	0.80	0.05	9	8	1	1000*	1	
WILSON CREEK									
PEKISKO A	51	0.85	0.10	39	3	36	1120*	40	7900
BANFF A	15	0.85	0.15	11		11	1120*	12	1100
WIMBORNE									
VIKING	2	0.75	0.05	1		1	1020	1	
RUNDLE	2	0.90	0.10	1		1	1100	1	
D-2	1	0.85	0.15	1		1	1160	1	
D-2 ASSOC	2	0.80	0.15	2		2	1160	2	
D-3 A ASSOC	360	0.70	0.25	190**					15080
D-3 A SOLN	110	0.90	0.32	7**	54**	143	1000*	143	
WINDFALL									
VIKING A	17	0.75	0.05	12		12	1030	12	9980
RUNDLE	5	0.85	0.05	4	2	2	1040	2	
D-3	3	0.90	0.35	2		2	1080*	2	
D-3 A ASSOC	710	0.80	0.30	400**					11600
D-3 A SOLN	230	0.70	0.35	110**	77**	433	1080*	468	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
48	0.09	0.45	1840	145	0.85	0.64	5080	1968	1968 TCPL
									1968
									1961
14	0.21	0.45	1110	75	0.87	0.57	2900	1950	1966 LOCAL UTILITY
6	0.20	0.25	1150	75	0.86	0.57	2180	1959	1966 LOCAL UTILITY
5	0.21	0.30	1430	105	0.82	0.58	3240	1951	1966
									1957
		GIP BASED ON MATERIAL BALANCE					9880	1958	1969 A&S
123	0.08	0.15	3200	140	0.85	0.68	7380	1960	1968
									1953 NUL
4	0.25	0.40	1110	90	0.86	0.61	3030	1952	1967 TCPL
7	0.25	0.40	1130	90	0.87	0.59	3090	1952	1967 TCPL
16	0.15	0.25	1600	145	0.82	0.70	5050	1967	1967
									1965
									1961
6	0.09	0.30	2950	135	0.81	0.69	5910	1962	1969
							6190	1954	1969 A&S
									1962
									1965
									1956
									1956
									1961 WESTERN MINERALS AND
									1961 LOCAL UTILITY
									1965 WESTERN MINERALS
19	0.06	0.25	2800	190	0.87	0.68	7040	1960	1966 A&S
37	0.06	0.25	2800	195	0.87	0.70	7290	1961	1966 A&S
									1956
									1961
									1959
									1959
41	0.08	0.10	3010	175	0.83	0.78	7480	1954	1969
									1969 TCPL
6	0.08	0.20	1570	145	0.87	0.63	5140	1955	1963
									1961 A&S
									1961
116	0.06	0.15	3790	220	0.83	0.81	9050	1955	1967 A&S - PRESSURE
							9100	1955	1966 MAINTAINED WITH PINE CREEK & PINE NW GAS

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVIN

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WINNIFRED									
BOW ISLAND A	19	0.85	0.05	16		16	1000	16	22560
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	1000	1	
WINIFRING HILLS									
BELLY RIVER	2	0.75	0.05	1		1	1000	1	
VIKING D	12	0.90	0.05	10		10	1010	10	1100
VIKING (OTHER)	14	0.85	0.05	11	2	9	1010	9	
VIKING ASSOC	2	0.85	0.05	1		1	1010	1	
MANNVILLE	23	0.80	0.10	18		18	1090	20	
LOWER MANN E ASSOC	17	0.75	0.10	12	1	11	1090	12	2850
MANN ASSOC (OTHER)	5	0.80	0.05	4		4	1090	4	
RUNDLE	2	0.80	0.05	1		1	1090	1	
WIZARD LAKE									
BELLY RIVER	2	0.75	0.05	1		1	1050	1	
VIKING	1	0.85	0.05	1		1	1070	1	
BASAL QUARTZ A	14	0.90	0.19	10	10	□ 1	1120	□ 1	
MANNVILLE (OTHER)	7	0.85	0.15	5	1	4	1120	4	
D-2 ASSOC	1	0.85	0.20	1		1	1180	1	
D-3 A SOLN	230	0.65	0.25	110	26	84	1250	105	
WOKING									
PEACE RIVER	5	0.90	0.05	4		4	1040	4	
SPIRIT RIVER	3	0.80	0.05	2		2	1040	2	
BLUESKY	4	0.80	0.05	3	1	2	1040	2	
PERMO-PENN	2	0.80	0.05	2		2	1060	2	
KISKATINAW	3	0.75	0.05	2		2	1070	2	
WOOD RIVER									
MANNVILLE	31	0.85	0.10	24	11	13	1100	14	
WORSLEY									
D-3 A	27	0.85	0.07	21	18	3	950*	3	
D-3 B	29	0.85	0.07	23	18	5	950*	5	
D-3 D	39	0.85	0.10	30	26	4	950*	4	1000
D-3 E	16	0.85	0.05	13	4	9	950*	9	500
D-3 G	65	0.85	0.05	53	20	33	950*	31	3700
D-3 (OTHER)	4	0.85	0.05	3	1	2	950*	2	
D-3 ASSOC	1	0.80	0.05	1		1	950*	1	
YEKAU LAKE									
VIKING	8	0.80	0.02	7	2	5	1070	5	
ZAMA									
SLAVE POINT	76	0.90	0.10	60		60	1050*	63	
SULPHUR POINT	260	0.85	0.15	190		190	1050*	200	
SULPHUR POINT ASSOC	9	0.85	0.15	6		6	1050*	6	
SULPHUR POINT SOLN	6	0.70	0.25	3		3	1100*	3	
MUSKEG SOLN	23	0.70	0.25	12		12	1100*	13	
KEG RIVER	14	0.90	0.20	10		10	1150*	12	
KEG RIVER ASSOC	15	0.85	0.55	7		7	1150*	8	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
4	0.20	0.40	730	85	0.92	0.59	2080	1963	1966 LOCAL UTILITY	2
									1969	3
										4
										5
									1963 TCPL	6
19	0.20	0.30	1280	90	0.86	0.65	3130	1955	1965	7
									1966 TCPL	8
									1969	9
										10
									1968 TCPL	11
13	0.17	0.35	1410	105	0.80	0.70	4110	1966	1968 TCPL	12
									1966	13
									1963	14
										15
										16
									1966	17
									1960 NUL	18
		GIP BASED ON MATERIAL BALANCE					4780	1951	1969 NUL	19
									1959 NUL	20
										21
									1968	22
							6460	1951	1966 NUL	23
										24
										25
									1961	26
									1961	27
									1961 LOCAL UTILITY	28
									1961	29
										30
									1961 LOCAL UTILITY	31
										32
										33
									1961 TCPL	34
										35
										36
		GIP BASED ON MATERIAL BALANCE					7420	1960	1969 WESTCOAST	37
		GIP BASED ON MATERIAL BALANCE					7240	1960	1966 WESTCOAST	38
60	0.10	0.20	3090	180	0.89	0.73	7660	1961	1966 WESTCOAST	39
42	0.11	0.20	3060	170	0.91	0.67	7030	1966	1966 WESTCOAST	40
										41
42	0.06	0.20	3300	180	0.91	0.64	7280	1959	1966 WESTCOAST	42
									1966 WESTCOAST	43
									1965	44
										45
										46
									1969 INJECTED INTO LEDUC-	47
									WOODBEND	48
										49
										50
									1967 CONSIDERED BEYOND	51
									1967 ECONOMIC REACH	52
									1967	53
									1969	54
										55
									1969	56
									1967	57
									1967	58

TABLE A-1 - CONT'D - ESTABLISHED RESERVES OF GAS IN THE PROVINC

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED DEC. 31/69 BCF	REMAINING MARKETABLE GAS DEC. 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ZAMA (CONTINUED)									
KEG RIVER SOLN	150	0.65	0.25	74		74	1200*	89	
SUB TOTAL	89787			53666	9713	43953		46350	
OTHER RESERVES									
LESS THAN 10 BCF	1308			782		782		821	
CONFIDENTIAL POOLS	771			461		461		484	
TOTAL RESERVES	91866			54909	9713	45196		47655	
WITHIN ECONOMIC REACH	88043			52467	9713	42754		44981	
BEYOND ECONOMIC REACH	3823			2442		2442		2674	

OF ALBERTA, DECEMBER 31, 1969 (14.65 PSIA AND 60°F.)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
									1969	1
										2
										3
										4
										5
										6
										7
										8
										9
										10
										11
										12
										13
										14
										15
										16
										17
										18

APPENDIX B

THE GROWTH TREND OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The reserves considered in this appendix in determining the trends in the growth of reserves are the initial marketable reserves without adjustment for heating value.

Growth of Reserves

The amount of future reserves to be included in calculating the future surplus is based on the growth rate in the most recent 10-year period, as described in Board Report OGCB 69-D[1].

(1) Views of TransCanada

TransCanada did not present a detailed study of the trends in the growth of gas reserves in the Province. It estimated the initial marketable gas reserves in the Province, as of February 1, 1970, to be 55.2 trillion cubic feet. This estimate was made by adding the 1.6 trillion cubic feet increase which it estimated had occurred in the fields under contract to TransCanada and in some other fields and areas, to the Board's estimate of the initial marketable reserves of the Province as of November 30, 1969.

TransCanada estimated the average growth rate over the last 10 years from its estimate of the initial marketable gas reserves at February 1, 1970, and the Board's estimate of the initial marketable gas reserves as of September 30, 1959, of 28.0 trillion cubic feet (adjusted to 14.65 pounds per square

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

inch absolute). It thus determined the 10-year growth rate to be 2.7 trillion cubic feet per year.

(2) Views of the Board

The Board, in OGCB Report 70-18[2] reviewed in detail the long term trend in the growth of initial marketable gas reserves in the Province to December 31, 1969, and concluded that the long term growth rate was 2.5 trillion cubic feet per year and the rate over the last 10 years was 2.6 trillion cubic feet per year. The ten-year growth rate was determined from the Board's estimates at September 30, 1959, and December 31, 1969. The September 30, 1959[3] estimate was 28.0 trillion cubic feet, as mentioned above, and the estimate of initial reserves at December 31, 1969, was 54.9 trillion cubic feet. Using the initial marketable gas reserve in OGCB Report 65-8[4] of 39.8 trillion cubic feet at December 31, 1964, and in OGCB Report 68-18[5] of 47.0 trillion cubic feet at December 31, 1967,

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(2) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur Province of Alberta. December 31, 1969.

(3) Report to the Lieutenant Governor in Council with Respect to the applications under The Gas Resources Preservation Act, 1956 of: Alberta and Southern Gas Co. Ltd., Saskatchewan Power Corporation, Trans-Canada Pipe Lines Limited, Westcoast Transmission Company Limited. December, 1959.

(4) Reserves of Gas, Natural Gas Liquids, Crude Oil and Sulphur Province of Alberta. December 31, 1964.

(5) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur Province of Alberta. December 31, 1967.

the annual growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet and 3.9 trillion cubic feet respectively. On the basis of these growth rates and its policy, the Board adopts an average growth rate of 2.6 trillion cubic feet per year in estimating the growth of initial gas reserves over the next four or five years.

Ultimate Reserves

Neither TransCanada nor any of the interveners submitted new evidence respecting the ultimate gas reserves of the Province. The Board in OGCB Report 70-18 analyzed the ultimate reserves of the Province in considerable detail and gave careful consideration to the views expressed on this matter in the submission of the Alberta Division of the Canadian Petroleum Association at the hearing of June 18, 1969, reported on in OGCB 69-D. The Canadian Petroleum Association's estimate of the ultimate marketable reserves was 120 trillion cubic feet. However, the Board retains the view expressed in Board OGCB Report 70-18 that the ultimate gas reserves of the Province will be of the order of 100 trillion cubic feet.

Future Reserves to be Considered

The Board, in the report OGCB 69-D, adopted the following formula for determining the future reserves to be considered:

$$T_G = \frac{R_{POT} - R_{EST}}{10}$$

where T_G = Years of growth of gas reserves;

R_{POT} = Potential initial marketable reserves of the Province, trillions of cubic feet; and

R_{EST} = Established initial marketable reserves at the time of application of the formula, trillions of cubic feet.

(1) Views of TransCanada

TransCanada used 11.7 trillion cubic feet of future reserves in calculating the future surplus. This corresponds to 4.5 years of growth at an average annual growth rate of 2.6 trillion cubic feet per year.

(2) Views of the Board

The future reserves to be considered in calculating the future surplus using the initial established reserves of 54.9 trillion cubic feet estimated as of December 31, 1969, and ultimate reserves of 100 trillion cubic feet are 11.7 trillion cubic feet. This corresponds to 4.5 years of growth at the 10-year growth rate of 2.6 trillion cubic feet per year.

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PRESENT PERMIT COMMITMENTS

Alberta Requirements

Neither TransCanada nor the interveners presented a new forecast of Alberta's 30-year requirements. For purposes of its surplus calculation, TransCanada relied upon the Board's forecast of 15.7 trillion cubic feet which was published in OGCB Report 69-F[(1)] and related to the period June 1, 1969 to May 31, 1999. At the hearing, TransCanada acknowledged that that estimate of Alberta requirements should be updated to cover the 30-year period commencing with the new reserve assessment date of December 31, 1969.

In view of the Board's decision to hold a requirements hearing on July 2, 1970, the Board does not feel it necessary at this time to undertake a detailed review of its 30-year forecast of Alberta requirements published in OGCB Report 70-A[(2)]. Rather, the Board has decided to update the previous forecast to cover the period January 1, 1970 to December 31, 1999. In addition, the Board has revised its forecast of other industrial requirements to include a provision for the Trunk Line fuel and reprocessing plant fuel and shrinkage expected to result from the permit recently granted to Alberta and Southern. The allowance relating to the Alberta and Southern permit totals some 56 billion cubic feet of 1000 Btu gas over the forecast period.

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(1) In the Matter of an Application of Trans-Canada Pipelines Limited under The Gas Resources Preservation Act, 1956. November 1969.

(2) In the Matter of an Application of Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. January 1970.

Considered on an annual basis, this allowance increases estimated other industrial requirements to some 70 billion cubic feet of 1000 Btu gas in 1970, of which 69 billion cubic feet are related to permits for the removal of gas from the Province. The corresponding 30-year other industrial requirements total some 1,533 billion cubic feet, of which 1,512 billion cubic feet are permit related.

The Board's forecast of Alberta gas requirements for the period January 1, 1970 to December 31, 1999 is summarized in Table C-1.

Permit Commitments:

The present permit commitments of the Province are listed in Table C-2. The remaining authorized withdrawals associated with these permits comprise removal volumes outstanding on permits approved by the Alberta Government on or before December 31, 1969, plus the recent volumes granted to Consolidated, Alberta and Southern and Mobil Oil Canada, Ltd. In total, the remaining authorized withdrawals of Alberta natural gas amount to some 29.6 trillion cubic feet, equivalent to 30.1 trillion cubic feet of 1000 Btu gas.

TABLE C-1

Summary of Forecast of Alberta Gas Requirements For Period January 1, 1970 to December 31, 1999 (Billions of Cubic Feet of 1,000 Btu Gas)

	Revised Board[1] 1966
Domestic	
1970 Annual	58.1
1999 Annual	129.7
30-year Total	2,733.4
Commercial	
1970 Annual	45.6
1999 Annual	108.6
30-year Total	2,239.6
Industrial & Contingency	
1970 Annual[2] [3]	209.5
1999 Annual	503.4
30-year Total	11,330.8
Total	
1970 Annual[2] [3]	313.2
1999 Annual	741.6
30-year Total	16,303.7
Equivalent Average Annual Growth Rate to Achieve Terminal Year[4] (%)	3.2
Equivalent Average Annual Growth Rate to Achieve 30-year Total[4] (%)	3.9

(1) The last detailed Board forecast was prepared in 1966.

(2) Includes 69 Bcf of requirements related to permits for the removal of gas from the Province.

(3) Industrial and Total numbers adjusted to include Board's revised estimate of other industrial consumption.

(4) Based on 1969 actual consumption of 286.0 Bcf.

TABLE C-2

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60^{O}F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO DEC. 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
AS 69-5	ALBERTA AND SOUTHERN GAS CO. LTD.	1,270.0	416.0	10,000.0	1,562.1	8,437.9
	BELLOY, BERLAND RIVER, BIGORAY, BIGSTONE, BRAZEAU RIVER, CAROLINE, CARSON CREEK, CARSON CREEK NORTH, CROSSFIELD (RUNDLE A POOL), EAGLESHAM, FERRIER (VIKING A AND CARDIUM B POOLS), FOX CREEK, GOLD CREEK, HARMATTAN-ELKTON (D-3A POOL), HOMEGLEN-RIMBEY, HUNTER VALLEY, JUDY CREEK, KAYBOB, KAYBOB SOUTH (VIKING A, CADOMIN A, CADOMIN B, CADOMIN C, CADOMIN D, TRIASSIC A AND BEAVERHILL LAKE A POOLS), MARLBORO, MINNEHIK-BUCK LAKE, OPEN CREEK, PEMBINA (LOBSTICK GLAUCONITIC A, LOBSTICK GLAUCONITIC C, LOBSTICK GLAUCONITIC D, LOBSTICK OSTRACOD A, LOBSTICK OSTRACOD B AND PEKISKO B POOLS), PINE CREEK, PINE NORTH-WEST, SIMONETTE, STURGEON LAKE SOUTH, SUNDRE, SWAN HILLS, SWAN HILLS SOUTH, SYLVAN LAKE, TANGENT, VIRGINIA HILLS, WASKAHIGAN, WATERTON, WESTEROSE SOUTH, WESTWARD HO, WILDCAT HILLS, WILDHORSE CREEK, WILLESDEN GREEN, WILSON CREEK AND WINDFALL.					
CD 63-1	CANADIAN DELHI OIL LTD. - MEDICINE HAT	4.3	1.57	32.3	4.5	27.8

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSI AND $60^{0}F$)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT		PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO DEC. 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
CM 54-1 AND CM 61-2	CANADIAN-MONTANA PIPELINE COMPANY		100.0	20.0	504.0 (1)	258.5	245.5
	ADEN, BLACK BUTTE, COMREY, KNAPPEN, MANYBERRIES, PAKOWKI LAKE, PENDANT D'OREILLE AND SMITH COULEE.						
CP 63-1	CANADIAN PACIFIC OIL AND GAS LIMITED	- MEDICINE HAT	0.1	0.0365	0.750	0.143	0.607
CNG 69-1	CONSOLIDATED NATURAL GAS LIMITED		240.0	80.0	1,535.0	-	1,535.0
	KAYBOB SOUTH (BEAVERHILL LAKE A POOL), RICINUS, RICINUS WEST AND STRACHAN.						
BH 61-1	DELTA GAS & TRANSMISSION LTD.						
BS 61-1	BAILEY SELBURN OIL AND GAS LTD.						
CS 61-1	THE CALIFORNIA STANDARD COMPANY						
COG 61-1	CHARTER OIL AND GAS LTD.	MEDICINE HAT	9.5	3.5	71.0	-	71.0
SEL 61-1	SELBAY EXPLORATION LTD.						
JMW 61-1	J MERRIL WRIGHT, JR.						
CEL 61-1	CROWFOOT EXPLORATION LTD.						
CMM 61-1	IMPERIAL OIL DEVELOPMENTS LIMITED						
MOG 61-1	MIC MAC OILS (1963) LTD.	MEDICINE HAT	8.512	3.1068	62.0	11.6	50.4
ROC 61-1	RICHFIELD OIL CORPORATION						
ROC 65-2	ATLANTIC RICHFIELD COMPANY	- MEDICINE HAT	0.26	0.088	2.0	0.2	1.8
HB 63-1	HUDSON'S BAY OIL AND GAS COMPANY LIMITED	- MEDICINE HAT	1.02	0.372	7.65	0.65	7.00
SPC 57-1	MANY ISLAND PIPE LINES LTD.	- MEDICINE HAT	135.55	44.53	609.4	221.7	387.7
MO 66-1	MURPHY OIL COMPANY LTD.	- RED COULEE	0.6	-	0.5	-	0.5
NSU 64-1	THE BRITISH AMERICAN OIL COMPANY, LIMITED, ROYALITE OIL COMPANY,	- ANTELOPE AND ESTHER	11.4	4.2	40.0	11.7	28.3

(1) TOTAL INITIAL MARKETABLE GAS IN THE FIELDS SHOWN

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSI AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO DEC. 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	LIMITED, SUN OIL COMPANY AND UNITED CANSO OIL & GAS LTD.					
MOC 70-1	MOBIL OIL CANADA, LTD. - MOBIL OYEN 10-4-30-2	2.0	0.73	4.69	-	4.69
	PEACE RIVER TRANSMISSION COMPANY LIMITED - POUCE COUPE	6.0	0.6	13.0	12.5	20.2
	PEACE RIVER TRANSMISSION COMPANY LIMITED - POUCE COUPE SOUTH	6.9	0.98	19.7		
B 68-1	PATRICK T. BUCKLEY - VANALTA NO. 4 WELL	1.0 MMCF PER MONTH	0.005	-	0.06	-
TC 69-9	TRANS-CANADA PIPE LINES LIMITED	2,910.0	932.0	21,400.0	3,602.8	17,797.2
	ALDERSON, ALIX, AMISK, ARMADA, ATLEE-BUFFALO, BANTRY, BASHAW, BASSANO, BELLIS, BERRY, BIG BEND, BINDLOSS, BIRCH, BLACK DIAMOND, BLUERIDGE, BOYLE, BRAZEAU RIVER, BRUCE, BURNT TIMBER, CAROLINE (VIKING A, VIKING E, AND BASAL MANNVILLE A POOLS), CARSTAIRS, CASSILS, CASTOR, CESSFORD, CHESTERMERE, CHIGWELL, CLIVE, CONNORSVILLE, COUNTESS, CRAIGEND, CROSSFIELD, CROSSFIELD EAST, DRUMHELLER, EDSON, ENCHANT, EQUITY, ERSKINE, FENN WEST, FERRIER, FIGURE LAKE, FLAT, GARRINGTON (MANNVILLE A AND LEDUC A POOLS), GHOST PINE, GILBY, GOODWIN, GREENCOURT, HACKETT, HALLIDAY, HARMATTAN EAST, HARMATTAN-ELKTON (RUNDLE A POOL), HOMEGLEN-RIMBEY, HUGHENDEN, HUNTER VALLEY, HUSSAR, INNISFAIL, JARROW, JENNER, JOHNSON, JUMPING POUND WEST, KILLAM, KITSIM, LATHOM, LECKIE, LITTLE BOW,					

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY	PERMITTED WITHDRAWALS MAXIMUM ANNUAL	PERMITTED WITHDRAWALS TOTAL	WITHDRAWN TO DEC. 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	LONE PINE CREEK, LONG COULEE, LOOKOUT BUTTE, MALMO, MARTEN HILLS, MCMULLEN, MEDICINE HAT, MEDICINE RIVER, MIKWAN, MITSUE, MOOSE, NEVIS, NEWELL, NEW NORWAY, OBED, OLDS, OYEN, PARFLESH, PELICAN, PINCHER CREEK, PLAIN, PREVO, PRINCESS, PROVOST, QUIRK CREEK, RAINIER, RANFURLY, RETLAW, RICH, RICHDALE, RICINUS, ROWLEY, SCANDIA, SEDALIA, SEDGEWICK, SEIU LAKE, SIBBALD, STANDARD, STRACHAN, SUNDRE (BASAL MANNVILLE A AND BASAL MANNVILLE B POOLS), SUNNYNOOK, SWALWELL, SYLVAN LAKE, THREE HILLS CREEK, TROCHU, TURIN, TWINING NORTH, VERGER, VULCAN, WAYNE-ROSEDALE, WESTEROSE, WESTEROSE SOUTH, WHISKEY, WHITECOURT, WILDHORSE CREEK, WILDUNN CREEK, WILLESDEN GREEN, WIMBORNE, WINNIFRED, WINTERING HILLS AND WOOD RIVER.					
WC 52-1	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.	125.0	35.0	388.0	250.5	137.5
	BRAEBURN, GORDONDALE, POUCE COUPE AND POUCE COUPE SOUTH.					
WC 61-4	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.	VOLUMES NOT TO EXCEED THOSE AUTHORIZED IN PERMIT NO. WC 52-1				
	BOUNDARY LAKE SOUTH					

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND $60^{0}F$)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY	PERMITTED WITHDRAWALS MAXIMUM ANNUAL	PERMITTED WITHDRAWALS TOTAL	WITHDRAWN TO DEC. 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
WC 59-3	WESTCOAST TRANSMISSION COMPANY LIMITED	162.2	53.1	1,081.2	365.2	716.0
	CROSSFIELD (CALGARY BASAL QUARTZ, CALGARY RUNDLE AND CALGARY WABAMUN POOLS), IRRICANA, AND SAVANNA CREEK.					
WC 62-5	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.	53.3	16.0	220.0	85.9	134.1
	WORSLEY					
		5,046.675	1,611.8183	35,991.190	6,388.053	29,603.197

APPENDIX D

THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

(1) Views of TransCanada

TransCanada did not present detailed evidence to show how Alberta's 30-year requirements for gas might be met, but did estimate the surplus of gas in the Province employing the method in use by the Board at the time the application was made. With respect to the total Alberta requirements, the applicant used the Board's estimate as shown in OGCB Report 69-F[1]. In determining the Alberta reserves, TransCanada compared its current estimate of field reserves with the most recent estimates of the Board and adjusted the total reserves accordingly. The applicant stated that it had reviewed the development activity and discovery information available to it for fields and areas where it has not contracted for gas, and estimated that the corresponding reserves had increased by 0.8 trillion cubic feet from the time of the Board's previous estimate to February 1, 1970.

TransCanada submitted a detailed table showing its determination of the contractable and future surplus as of November 24, 1969. Some of the data were revised by the applicant at the hearing to reflect the contractable surplus position as of February 1, 1970. The reconstructed TransCanada surplus table,

(1) In the matter of an Application of Trans-Canada Pipelines Limited under The Gas Resources Preservation Act, 1956. November 1969.

included here as Table D-5, showed that the contractable reserves at February 1, 1970 exceeded the contractable requirements by 2.8 trillion cubic feet. TransCanada stated that minor changes should be made to update the future surplus calculation to February 1, 1970 but in view of the magnitude of the future surplus, some 6.6 trillion cubic feet, no change was made. An overall surplus of 9.4 trillion cubic feet resulted after taking account of the contractable surplus of 2.8 trillion cubic feet.

TransCanada submitted that the 960 billion cubic feet of gas it sought authorization to remove from the Province is therefore surplus to the needs of Alberta.

(2) Views of Interveners

None of the interveners at the hearing submitted evidence respecting the meeting of Alberta's 30-year requirements for gas and the permit commitments.

(3) Views of the Board

<u>The meeting of Alberta's long term requirements (January 1, 1970 to December 31, 1999).</u> As shown in Appendix C, the 30-year gas requirements for delivery to markets within the Province have been estimated by the Board to be some 16.3 trillion cubic feet. Of this total, some 1.5 trillion cubic feet are required for the fuel and shrinkage associated with permits for the removal of gas from the Province; hence the estimated Alberta non-permit related requirements are 14.8 trillion cubic feet. The peak day requirement in the 30th year is estimated to be some 3.6 billion cubic feet. In view of the policy changes recently adopted and described in Section III the contractable Alberta requirements should be taken as the

greater of

(a) the remaining reserves of those fields connected to and supplying Alberta requirements, or

(b) the sum of the permit-related Alberta requirements and 30 times the non-permit related Alberta requirements of the first year of the period under consideration.

The first quantity currently comprises the reserves of pools shown in Table D-1 which total 6.3 trillion cubic feet and the second quantity is currently 8.8 trillion cubic feet. The contractable Alberta requirements are therefore 8.8 trillion cubic feet.

Table D-1 shows also the Board's interpretation of the reserve-delivery ratio of each of the fields and the average reserve-delivery ratio of the group of fields supplying Alberta requirements. The reserves are classified in the table between major reserves, oil field gas, and small reserves plus reserves supplying small utilities. The reserve-delivery ratio is the initial gas in place adjusted for surface losses divided by the initial fully developed marketable gas deliverability. The ratios have been updated to take account of changes in reserves of pools, additional deliverability data and new discoveries.

The Board estimates from a review of deliverability schedules and industry practice that three-quarters of the reserves of 6.3 trillion cubic feet connected to and supplying Alberta requirements will be produced during the thirty-year period and that this ratio can reasonably be applied to the total reserves of 8.8 trillion cubic feet required for contractable Alberta requirements.

It follows that of the total of some 8.8 trillion cubic feet needed to supply the contractable Alberta requirements, some 6.6 trillion cubic feet will be produced during the 30-year period and the remaining unproduced portion will be capable of sustaining a peak day delivery of some 660 million cubic feet in the 30th year. Therefore, total deliveries of about 9.7 trillion cubic feet (16.3 - 6.6 = 9.7) and a 30th-year peak day delivery of about 2,940 million cubic feet (3,600 - 660 = 2,940) will be required from other sources.

The actual quantities of gas necessary to provide these deliveries may be calculated using the formula method presented in Appendix E of OGCB Report 64-11[2]. With respect to the factors to be used in the formula, the Board believes that since this gas must come in part from established gas reserves not now connected to local utilities nor authorized for removal from the Province and in part from gas reserves not yet developed, the factors should reflect the delivery characteristics of both of these sources of gas.

The Board has again reviewed the average reserve-delivery ratio to take account of changes which have occurred since the issuance of OGCB Report 69-F. It finds, as is illustrated in Table D-2, that the average reserve-delivery ratio of 2.0 previously used remains applicable. The Board has also reviewed

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(2) Report on the Application of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

the average reservoir recovery factor of the gas in place adjusted for surface losses and finds the factor of 0.74 as used in OGCB Report 69-F, to be appropriate.

The following is a detailed calculation of the gas reserves in billions of cubic feet necessary to meet Alberta's 30-year requirements:

From now connected sources and additional sources needed to supply the contractable requirements, for delivery during the period	6,600	
From additional sources for delivery during the period	9,700	
Total Alberta Requirements for delivery		16,300
From now connected sources and additional sources needed to supply the contractable requirements, to protect the 30th year peak(1)	2,200	
From additional sources to protect the 30th year peak(2)	3,100	
Total Alberta Requirements for peak day protection		5,300
Total Alberta Requirements		21,600

(1) i.e. 8,800 - 6,600 = 2,200

(2) Determined as $R_P = 1.3\ FP_n - (1-K)\ (1.3\ FP_n + A_1S)$

$$= 1.3\ (2.0)\ (2{,}940) - (1 - 0.74)\left[1.3\ (2.0)\ (2{,}940) + 9{,}700\right]$$

$$= 7{,}644 - 4{,}509 = 3{,}135;\ \text{say } 3{,}100 \text{ billion cubic feet}$$

<u>The Remaining Permit Commitments</u>. The permit commitments remaining at December 31, 1969, are shown in Appendix C to be some 29.6 trillion cubic feet before adjustments for heating value and deficiencies in reserves in certain permits.

The fields included in each of the permits are shown in Table D-3. The table shows the Board's current estimate of the remaining reserves of marketable gas and the ratio of initial marketable gas in place to delivery capacity for each field. The table reflects changes in the remaining marketable reserves which have occurred since the preparation of OGCB Report 69-F and also incorporates revisions to reserve-delivery ratios resulting from additional data respecting pool deliverability.

In Tables D-1 and D-3, the remaining reserves of some 29 fields have been divided between permittees or between permittees and provincial requirements on the basis of the Board's knowledge of the gas purchase contracts involved and in accordance with the Board policy set out in Board report OGCB 69-D[3].

TransCanada stated that a number of fields which have been included in its permit for some time and which are not yet producing are under reasonably active consideration by the parties involved. Two small non-producing permit fields were considered by TransCanada to have only a small possibility of being placed on production in the near future. The applicant requested that all of the fields be retained in the permit for at least another year. Upon consideration of the reserves and circumstances in each case, the Board is satisfied that all of the non-producing fields discussed above should remain in TransCanada's permit at the present time.

The results of the Board's analysis with respect to the

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(3) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

meeting of the remaining permit commitments are shown in Table D-4. Columns 1 and 2 show respectively the remaining permit commitment and the maximum daily withdrawal authorized in each of the permits. These figures were obtained from Appendix C and have been adjusted where necessary for any deficiency in reserves in the fields, pools and areas named in the permit and also have been converted to the basis of 1000 Btu per cubic foot using the expected average heating value of the gas as it leaves the Province. The expiry date of each of the permits is shown in column 3, and column 4 presents the Board's current estimate of the total remaining marketable reserves (from Table D-3) of the fields included in each permit. Column 5 shows the marketable gas in place required to meet the peak day commitments in the terminal year of two early permits for which provision for peak day protection was provided initially and remains in effect. The total marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in column 6. Columns 7 and 8 present the Board's estimate of the marketable gas in the fields in the permits in excess of the permit commitments, before and after the expiry date of each permit.

The remaining commitment of the Westcoast Peace River Permits provides for an adjustment described more fully in OGCB Report 66-C(4) and in Permit No. WC 62-5, related to the delivery of gas from the Worsley Field and the meeting of future requirements of an iron ore processing industry in the Peace River area. The reserves credited to these permits have been adjusted having regard for these provisions, field deliverability and the withdrawals

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(4) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June 1966.

taken from the area to December 31, 1965. The provision for this market in the estimated Alberta requirements is discussed in detail in Appendix C of OGCB Report 68-A[5].

Table D-4 shows that a total marketable gas reserve of 30.3 trillion cubic feet is required to meet the commitments of all subsisting permits of 30.1 trillion cubic feet. Since reserves of 33.4 trillion cubic feet are available in the permit fields, a surplus of 3.1 trillion cubic feet exists in the fields named in the permits. Several years before the end of the 30-year period, an additional 200 billion cubic feet, the amount allowed to meet the terminal year peak day deliveries for the Westcoast Permit No. WC 59-3, will also become excess to the existing permit commitments.

The Gas Surplus to Alberta's Requirements and the Permit Commitments. The surplus calculation using the method adopted by the Board and discussed in detail in OGCB 69-D is illustrated in Table D-6.

The table shows that the Board's estimate of contractable reserves, the reserves within economic reach (44.9 trillion cubic feet) less the deferred reserves (4.0 trillion cubic feet) totals some 40.9 trillion cubic feet. The deferred reserves are listed in Table D-7 and total 4.0 trillion cubic feet. The Board expects all these reserves to become marketable within 30 years.

As discussed in Section III, the Board has segregated the permit-related fuel and reprocessing shrinkage requirements from all other Alberta requirements in calculating the contractable

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(5) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

surplus. Table D-6 shows the non-permit-related Alberta requirements to be 7.3 trillion cubic feet, and the permit-related requirements to be 1.5 trillion cubic feet, giving a total Alberta contractable requirement of 8.8 trillion cubic feet. The permit requirements are some 30.3 trillion cubic feet. The comparison of the contractable reserves and the contractable requirements results in a contractable surplus of 1.8 trillion cubic feet.

The table shows that the remaining Alberta requirements total some 12.8 trillion cubic feet. These are made up of some 9.7 trillion cubic feet which the Board believes will have to be delivered during the 30-year period and some 3.1 trillion cubic feet which the Board estimates will be necessary to provide for the 30th-year peak day.

The remaining and future reserves available to meet these Alberta requirements are shown to total some 17.9 trillion cubic feet. These are made up of 4.0 trillion cubic feet of deferred gas which the Board believes will be available within the 30-year period, some 2.0 trillion cubic feet of reserves now beyond economic reach but which the Board believes will be within economic reach within 30 years, some 0.2 trillion cubic feet allocated to protect peak day requirements in certain permits but available within 30 years, and 11.7 trillion cubic feet of future reserves.

The details of the deferred reserves which will become marketable within 30 years are shown in Table D-7. The Board studies indicate that of the total deferred reserves of some 4.0 trillion cubic feet, about 2.2 trillion cubic feet will be

deliverable during the 30-year period and the remaining 1.8 trillion cubic feet will be available to assist in the meeting of the 30th-year peak day.

The 2.0 trillion cubic feet of reserves now beyond economic reach but expected to be available within 30 years were obtained by taking 75 per cent of the reserves now considered beyond economic each. The Board expects that essentially all of this gas will be deliverable during the 30-year period.

The 0.2 trillion cubic feet available from the cushion gas portion of the permit requirements results from detailed delivery schedules prepared for the Crossfield Field. Part of this cushion gas will be deliverable during the 30-year period and the remainder will be available towards the 30th-year peak day requirements.

The Board has made one further test prior to including all of the reserves available within 30 years from the above mentioned three categories in the future surplus calculation. Detailed studies indicate that some 4.3 trillion cubic feet of these reserves will actually be deliverable within 30 years and that the remaining 1.9 trillion cubic feet will be available to meet the 30th-year peak day requirement. Since the 1.9 trillion cubic feet is less than 3.1 trillion cubic feet shown earlier in Table D-6 as required from other sources to meet the 30th-year peak day, the Board believes that the total of these reserves, some 6.2 trillion cubic feet, should be included in remaining reserves.

The future reserves to be considered have been determined in Appendix B as 11.7 trillion cubic feet. Table D-6 shows that the total remaining reserves exceeed the total remaining requirements by 5.1 trillion cubic feet.

TABLE D-1

RESERVES AND RESERVE-DELIVERY RATIOS OF FIELDS
SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
MAJOR RESERVES			
BEAVERHILL LAKE - FORT SASKATCHEWAN		375	0.7
BOW ISLAND		29	0.7
CARBON		118	0.7
FAIRYDELL-BON ACCORD		79	0.4
FOREMOST		18	1.8
JUDY CREEK		17	0.4
JUMPING POUND		287	2.6
JUMPING POUND WEST		865	6.9
MEDICINE HAT		334	3.6
MORINVILLE		55	1.8
OKOTOKS		116	4.3
PADDLE RIVER		152	1.3
ST. ALBERT-BIG LAKE		48	1.3
SARCEE		106	1.4
TURNER VALLEY		193	14.2
VIKING KINSELLA		395	3.2
WAYNE-ROSEDALE		57	0.9
WESTLOCK		184	1.2
WORSLEY		69	0.5
	TOTAL	3,497	
	WEIGHTED AVERAGE		1.9
OIL FIELD GAS			
ACHESON		19	9.0
ACHESON EAST		4	6.7
BONNIE GLEN		268	8.4
FENN-BIG VALLEY		9	20.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-1 (CONTINUED)

FIELD		MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
GLEN PARK		9	24.3
JUDY CREEK		166	28.4
LEDUC WOODBEND		27	3.8
PEMBINA		820	39.5
REDWATER		43	26.2
SAMSON		2	4.6
SIMONETTE		25	25.6
STETTLER		2	30.0
STURGEON LAKE SOUTH		11	41.6
SWAN HILLS		211	42.5
SWAN HILLS SOUTH		115	26.9
VIRGINIA HILLS		32	32.1
WIZARD LAKE		105	22.5
	TOTAL	1,868	
	WEIGHTED AVERAGE		20.3
SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES			
ACHESON		22	0.6
ALDERSON		17	7.6
ALEXANDER		10	1.5
ATHABASCA		6	2.5
ATHABASCA EAST		2	0.6
ATIM		2	0.3
BANTRY		35	8.0
BEAVER CROSSING		1	0.4
BITTERN LAKE		93	1.9
BONNIE GLEN		9	8.5
BONNYVILLE		1	0.2
BROOKS		3	20.0
CALAIS		21	2.0
CALLING LAKE		35	1.5
CAMPBELL-NAMAO		19	3.9
CASTOR		14	0.6

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
CHARLOTTE LAKE	2	0.4
COLD LAKE	2	0.3
CRAIG LAKE	1	0.4
DOWLING LAKE	1	0.5
DUVERNAY	1	0.8
EDWAND	3	0.2
ELK POINT	1	1.0
ELLERSLIE	1	0.1
ETHEL LAKE	2	0.4
ETZIKOM	13	1.5
EXCELSIOR	36	1.4
FLAT	10	1.2
FORT KENT	2	0.2
GLEN PARK	5	0.8
HAIRY HILL	9	0.6
HAMELIN CREEK	33	1.5
HANNA	11	3.1
HEART RIVER	2	0.1
HERCULES	23	2.0
HOLMBERG	22	1.6
JOFFRE	32	7.4
KILLAM NORTH	18	1.6
KNOPCIK	12	2.6
LAC LA BICHE	7	1.3
LEAHURST	15	0.5
LEGAL	2	0.9
LINDBERGH	8	1.5
LLOYDMINSTER	2	0.5
MURIEL LAKE	5	0.7
NORMANDVILLE	38	2.6
OBERLIN	-	0.5

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
OWLSEYE	2	0.8
PROVOST	8	1.7
REDLAND	31	0.9
REDWATER	20	1.3
RYCROFT	12	0.6
SADDLE HILLS	52	5.6
ST. PAUL	-	0.8
SEXSMITH	5	0.6
STRATHMORE	15	2.5
STROME	3	1.0
STRUGEON LAKE SOUTH	2	0.7
THORHILD	11	1.8
TWEEDIE	62	0.7
WAINWRIGHT	17	0.7
WATTS	3	1.0
WHITELAW	45	4.5
WILDMERE	17	1.0
WILLINGDON	11	0.7
WINNIFRED	6	1.9
WIZARD LAKE	7	1.1
WOKING	12	0.8
TOTAL	950	
WEIGHTED AVERAGE		1.1
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS	6,315	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.0

TABLE D-2

SUMMARY OF RESERVES AND

AVERAGE RESERVE-DELIVERY RATIO FOR ALL

RESERVES IN THE PROVINCE

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE RESERVES AT DEC. 31, 1969 BCF	RESERVE-DELIVERY[1] RATIO BCF/MMCFD
RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS (SEE TABLE D-1)	6,315	2.6
FIELDS INCLUDED IN PERMITS (SEE TABLE D-3)	33,387	1.9
FIELDS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED (SEE TABLE E-1)	249	6.0
REMAINING ESTABLISHED RESERVES[2]	7,704	1.9
TOTAL RECOVERABLE RESERVES IN THE PROVINCE	47,655	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

(2) INCLUDES DEFERRED RESERVES AND RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH.

TABLE D-3

MARKETABLE RESERVES AVAILABLE AND RESERVE-DELIVERY RATIOS OF THE FIELDS INCLUDED IN PERMITS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY[(1)] RATIO BCF/MMCFD
ALBERTA AND SOUTHERN GAS CO. LTD. (PERMIT NO. AS 69-5)		
BELLOY	82	2.8
BERLAND RIVER	297	1.4
BIGORAY	32	1.8
BIGSTONE	314	3.3
BRAZEAU RIVER	214	2.8
CAROLINE	42	3.9
CARSON CREEK	252	0.8
CARSON CREEK NORTH	172	25.8
CROSSFIELD	847	1.2
EAGLESHAM	65	4.6
FERRIER	12	9.2
FOX CREEK	124	1.3
GOLD CREEK	404	3.4
HARMATTAN-ELKTON	94	2.8
HOMEGLEN-RIMBEY	143	0.6
HUNTER VALLEY	30	3.0
JUDY CREEK, SWAN HILLS, SWAN HILLS SOUTH AND VIRGINIA HILLS	304	12.3
KAYBOB	416	1.4
KAYBOB SOUTH	1,466	1.7
MARLBORO	100	5.2
MINNEHIK-BUCK LAKE	540	1.8
OPEN CREEK	36	4.7
PEMBINA	190	4.8
PINE CREEK	148	1.5
PINE NORTH-WEST	157	13.3
SIMONETTE	110	5.3

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-3 (CONTINUED)

FIELD		MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
STURGEON LAKE SOUTH		65	30.8
SUNDRE		33	9.3
SYLVAN LAKE		7	2.3
TANGENT		64	3.0
WASKAHIGAN		107	4.1
WATERTON		1,939	3.1
WESTEROSE SOUTH		432	0.5
WESTWARD HO		-	-
WILDCAT HILLS		565	5.7
WILDHORSE CREEK		56	4.6
WILLESDEN GREEN		153	12.9
WILSON CREEK		52	2.2
WINDFALL		484	1.0
	TOTAL	10,548	
	WEIGHTED AVERAGE		1.8
CANADIAN-MONTANA PIPELINE COMPANY (PERMIT NO. CM 54-1 AND CM 61-2)			
ADEN		28	2.8
BLACK BUTTE		38	3.4
COMREY		27	2.8
KNAPPEN		17	2.0
MANYBERRIES		6	1.1
PAKOWKI LAKE		9	1.4
PENDANT D'OREILLE		119	2.2
SMITH COULEE		2	1.1
	TOTAL	246	
	WEIGHTED AVERAGE		2.1
CONSOLIDATED NATURAL GAS LIMITED (PERMIT NO. CNG 69-1)			
KAYBOB SOUTH		1,141	1.1
RICINUS		44	23.3
RICINUS WEST		109	5.3
STRACHAN		548	3.1
	TOTAL	1,842	
	WEIGHTED AVERAGE		1.5

TABLE D-3 (Continued)

Field	Marketable Gas at Dec. 31, 1969 Bcf	Reserve-Delivery Ratio Bcf/MMcfd
<u>Trans-Canada Pipe Lines Limited</u> (Permit No. TC 69-9)		
Alderson	451	4.8
Alix	2	20.0
Amisk	9	4.5
Armada	9	2.2
Atlee-Buffalo	140	3.1
Bantry	24	11.7
Bashaw	34	0.3
Bassano	22	1.6
Bellis	45	2.1
Berry	8	2.5
Big Bend	68	3.2
Bindloss	219	3.4
Birch	13	2.5
Black Diamond	19	5.0
Blueridge	29	2.2
Boyle	11	0.8
Brazeau River	489	2.8
Bruce	26	1.5
Burnt Timber	258	10.2
Caroline	123	2.0
Carstairs	652	1.7
Cassils	9	5.6
Castor	26	12.7
Cessford	710	1.8
Chestermere	22	5.0
Chigwell	32	1.3
Clive	19	24.7
Connorsville	52	3.6
Countess	179	0.7
Craigend	210	1.8
Crossfield	473	2.5
Crossfield East	683	7.1
Drumheller	70	1.2

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
EDSON	1,905	2.0
ENCHANT	42	0.4
EQUITY	37	3.9
ERSKINE	46	1.6
FENN WEST	7	0.5
FERRIER	562	15.2
FIGURE LAKE	32	0.9
FLAT	124	1.3
GARRINGTON	7	5.6
GHOST PINE	211	1.7
GILBY	667	2.0
GOODWIN	17	8.2
GREENCOURT	159	1.5
HACKETT	45	1.4
HALLIDAY	3	1.4
HARMATTAN EAST	82	7.4
HARMATTAN-ELKTON	6	0.9
HOMEGLEN-RIMBEY	366	0.6
HUGHENDEN	5	4.4
HUNTER VALLEY	20	3.0
HUSSAR	315	0.8
INNISFAIL	78	6.1
JARROW	9	1.8
JENNER	40	1.2
JOHNSON	-	-
JUMPING POUND WEST	117	5.2
KILLAM	15	0.5
KITSOM	7	2.7
LATHOM	7	1.7
LECKIE	1	0.7
LITTLE BOW	26	0.7

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
LONE PINE CREEK	342	3.8
LONG COULEE	16	0.6
LOOKOUT BUTTE	389	4.6
MALMO	49	1.0
MARTEN HILLS	879	1.8
MCMULLEN	7	1.1
MEDICINE HAT	296	5.7
MEDICINE RIVER	377	3.5
MIKWAN	14	4.3
MITSUE	211	58.9
MOOSE	55	10.3
NEVIS	631	1.8
NEWELL	2	0.5
NEW NORWAY	11	1.4
OBED	159	6.0
OLDS	214	2.9
OYEN	44	3.2
PARFLESH	9	1.7
PELICAN	14	6.1
PINCHER CREEK	288	12.2
PLAIN	56	1.5
PREVO	32	3.5
PRINCESS	126	2.0
PROVOST	680	1.7
QUIRK CREEK	555	5.6
RANIER	3	0.7
RANFURLY	9	1.3
RETLAW	90	1.9
RICH	11	1.2
RICHDALE	24	1.9
RICINUS	44	23.3
ROWLEY	67	2.7

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
SCANDIA	4	2.9
SEDALIA	49	9.7
SEDGEWICK	24	1.8
SEIU LAKE	11	3.6
SIBBALD	21	2.1
STANDARD	20	5.4
STRACHAN	772	3.6
SUNDRE	12	3.3
SUNNYNOOK	13	1.3
SWALWELL	44	3.9
SYLVAN LAKE	431	2.5
THREE HILLS CREEK	161	4.2
TROCHU	10	4.0
TURIN	30	3.0
TWINING NORTH	48	4.4
VERGER	39	0.8
VULCAN	29	1.6
WAYNE-ROSEDALE	282	1.0
WESTEROSE	76	21.0
WESTEROSE SOUTH	534	0.5
WHISKEY	111	13.4
WHITECOURT	117	1.0
WILDHORSE CREEK	55	5.5
WILDUNN CREEK	18	3.3
WILLESDEN GREEN	7	6.9
WIMBORNE	148	1.2
WINNIFRED	11	1.2
WINTERING HILLS	58	2.5
WOOD RIVER	14	1.4
TOTAL	18,947	
WEIGHTED AVERAGE		1.9

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
WESTCOAST TRANSMISSION COMPANY LIMITED (PERMIT NO. WC 59-3)		
CROSSFIELD	840	2.4
IRRICANA	10	4.1
SAVANNA CREEK	78	10.2
TOTAL	928	
WEIGHTED AVERAGE		2.6
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 52-1 AND WC 62-5)		
BRAEBURN	59	4.2
GORDONDALE	29	1.6
POUCE COUPE	23	2.0
POUCE COUPE SOUTH	40	1.2
WORSLEY	- 14	0.4
TOTAL	137	
WEIGHTED AVERAGE		1.2
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 61-4)		
BOUNDARY LAKE SOUTH	58	1.4
OTHERS		
ANTELOPE	12	0.9
ESTHER	28	0.9
MEDICINE HAT	640	2.3
RED COULEE	1	3.3
TOTAL	681	
WEIGHTED AVERAGE		2.1
TOTAL (ALL FIELDS)	33,387	
WEIGHTED AVERAGE (ALL FIELDS)		1.9

TABLE D-4

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS[1]

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	REMAINING PERMIT COMMITMENT (2)						EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	8,632	1,299	31/10/93	10,548		8,632	1,916	1,916
CANADIAN-MONTANA PIPE LINE COMPANY	246	100	15/3/86	246		246	-	-
CONSOLIDATED NATURAL GAS LIMITED	1,679	263	31/12/95	1,842		1,679	163	163
TRANS-CANADA PIPE LINES LIMITED (3)	17,993	2,942	31/10/94	18,947		17,993	954	954
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA) (3)	726	164	29/2/84	928	202	928	-	,202
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	1 95	179	31/12/79	195		195	-	-
OTHERS	583	180		681	23	606	75	98
TOTALS	30,054	5,127		33,387	225	30,279	3,108	3,333
ROUNDED TOTALS	30,100	5,100		33,400	200	30,300	3,100	3,300

(1) ALL FIGURES ARE AS OF DECEMBER 31, 1969.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANSCANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE D-5

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF FEBRUARY 1, 1970

AS ESTIMATED BY TRANSCANADA

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES					
Now considered within economic reach			44.9		
Less: Deferred			3.8		
Total Contractable Reserves				41.1	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta requirements			8.1		
Permit requirements: To meet commitments		29.9			
To meet terminal year peak day		0.3			
Total Contractable Requirements				38.3	
CONTRACTABLE SURPLUS					2.8
REMAINING REQUIREMENTS					
Total Alberta requirements for delivery	15.7				
Total Alberta requirements for thirtieth year peak day	5.0				
Total Alberta requirements		20.7			
Less: Available from contractable reserves		8.1			
Total Remaining Requirements			12.6		
REMAINING AND FUTURE RESERVES					
From deferred gas available within 30 years		5.1			
From reserves now considered beyond economic reach		2.1			
From reserves providing for terminal years peak day in permits		0.3			
From gas not yet established		11.7			
Total Remaining and Future Reserves			19.2		
FUTURE SURPLUS					6.6
OVERALL SURPLUS					9.4

TABLE D-6

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF DECEMBER 31, 1969

AS ESTIMATED BY THE BOARD

(All Volumes in Trillions of Cubic Feet at 1000 Btu Per Cubic Foot)

CONTRACTABLE RESERVES					
Now considered within economic reach			44.9		
Less: Deferred			4.0		
Total Contractable Reserves				40.9	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta requirements:					
General requirements		7.3			
Permit-related fuel and shrinkage		1.5			
Permit requirements: To meet remaining commitments		30.1			
To meet terminal year peak day		0.2			
Total Contractable Requirements				39.1	
CONTRACTABLE SURPLUS					1.8
REMAINING REQUIREMENTS					
Total Alberta requirements for delivery	16.3				
Less: Deliveries from contractable reserves	6.6				
Deliveries required from other sources		9.7			
Total Alberta requirements for thirtieth year peak day	5.3				
Less: Available from contractable reserves	2.2				
Required from other sources to meet thirtieth year peak day		3.1			
Total Remaining Requirements			12.8		
REMAINING AND FUTURE RESERVES					
From deferred gas available within 30 years		4.0			
From reserves now considered beyond economic reach		2.0			
From reserves providing for terminal years peak day in permits		0.2			
From gas not yet established		11.7			
Total Remaining and Future Reserves			17.9		
FUTURE SURPLUS					5.1

TABLE D-7

DEFERRED RESERVES

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

MARKETABLE WITHIN 30 YEARS	MARKETABLE RESERVES AT DECEMBER 31, 1969 BCF
BONNIE GLEN D-3A	378
GOLDEN SPIKE D-3A	248
HARMATTAN EAST RUNDLE	963
HARMATTAN-ELKTON RUNDLE C	1,065
KAYBOB CADOMIN B	64
KAYBOB SOUTH BEAVERHILL LAKE A	185
LEDUC-WOODBEND D-3A	365
RICINUS CARDIUM A	140
WESTEROSE D-3	102
OTHER SMALL AND CONFIDENTIAL RESERVES	514
TOTAL DEFERRED RESERVES	4,024

APPENDIX E

THE APPLICATION FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE EFFECT THE AUTHORIZATION WOULD HAVE ON SURPLUS

TransCanada is now authorized under Permit No. TC 69-9 to remove from the Province 21,400 billion cubic feet of gas, of which some 3,600 billion cubic feet have been removed to December 31, 1969. It applied for an increase of 960 billion cubic feet in the quantity authorized under Permit No. TC 69-9, bringing the total to 22,360 billion cubic feet of gas, at a maximum daily rate of 3,188 million cubic feet from the fields now named in its permits and from six new fields and areas. The volumes before and after adjustment to the basis of 1,000 Btu per cubic foot are compared below;

	As is Basis	1,000 Btu Basis
Total TransCanada permit volume May 31, 1969, Bcf	21,400	21,635
Addition applied for, Bcf	960	971
TransCanada permit volume if the application is granted, Bcf	22,360	22,606
Removed at December 31, 1969, Bcf	3,603	3,642
Remaining TransCanada permit volume if the application is granted, Bcf	18,757	18,964
Present maximum daily rate, MMcfd	2,910	2,942
Maximum daily rate applied for, MMcfd	3,118	3,149

All volumes subsequently referred to in this Appendix respecting the TransCanada permit are on the basis of 1,000 Btu per cubic foot.

TransCanada has applied for an increase of its remaining authorized withdrawals from 17,993 billion cubic feet as of December

31, 1969, to 18,964 billion cubic feet (21,635 - 3,642 = 17,993). Table E-1 shows proposed additions of fields or areas in the TransCanada permit and the Board's current estimate of the remaining reserves of marketable gas and the reserve-delivery ratio for each of the fields listed.

The results of the Board's analysis with respect to the meeting of permit commitments and the additional volumes applied for by TransCanada are presented in Table E-2, which is similar in form to the previously discussed Table D-4. The only changes have been to replace the TransCanada entry with a new entry reflecting the additional quantities applied for and reserves available in the fields from which the applicant proposed to remove gas.

The TransCanada entry in the table suggests that the remaining volume applied for of 18,964 billion cubic feet is less than the Board's estimate of total remaining reserves of fields which would be included in TransCanada's permit of 19,196 billion cubic feet. The latter figure includes only that portion of reserves which the Board considers available to TransCanada in those pools where more than one permittee has gas purchase contracts.

Since Alberta's requirements and the other permit volumes can be separately accommodated from other Alberta reserves, the Board believes the entire amount applied for may be included in the quantity considered for removal from the Province. However, no assurance can be given that the gas can be produced during the full term of the permit at the respective requested maximum daily rates.

Table E-2 further shows that, with the inclusion of the volumes applied for by TransCanada, the remaining permit commitments would total some 31.0 trillion cubic feet and the reserves required to meet these commitments would total some 31.2 trillion cubic feet.

Table E-3 presents the calculation of the amount of gas that would be surplus to Alberta's requirements and the permit commitments if the application of TransCanada were granted. Most of the figures used in the preparation of the table have been taken directly from Table D-6. The exception to this is the contractable permit requirements which are taken from Table E-2 and include the volumes applied for by TransCanada.

Table E-3 shows that on the basis of the Board's estimates there would remain a contractable surplus of 0.9 trillion cubic feet if TransCanada were authorized to remove the additional volumes applied for. The table also shows that the remaining and future reserves would exceed the remaining requirements by some 5.1 trillion cubic feet. Increased Alberta requirements of some 50 billion cubic feet over the 30-year period would likely result from approval of TransCanada's application due to additional extraction of natural gas liquids at the Empress gas reprocessing plants and increased fuel requirements of the Alberta Gas Trunk Line Company Limited. However, a sizable surplus would still remain after allowance for these anticipated additional requirements.

TABLE E-1

MARKETABLE RESERVES AND RESERVE-DELIVERY RATIO
OF FIELDS APPLIED FOR BY TRANSCANADA
(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT DEC. 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
ELNORA		35	1.7
KIRKWALL		2	2.0
NIPISI		115	43.2
RICINUS WEST		50	5.3
UKALTA		33	4.9
WARWICK		14	1.6
	TOTAL	249	
	WEIGHTED AVERAGE		6.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE E-2

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS INCLUDING

THE TRANSCANADA APPLICATION (1)

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	REMAINING PERMIT COMMITMENT (2)						EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	8,632	1,299	31/10/93	10,548		8,632	1,916	1,916
CANADIAN-MONTANA PIPE LINE COMPANY	246	100	15/3/86	246		246	-	-
CONSOLIDATED NATURAL GAS LIMITED	1,679	263	31/12/95	1,842		1,679	163	163
TRANS-CANADA PIPE LINES LIMITED (3)	18,964	3,149	31/10/94	19,196		18,964	232	232
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA) (3)	726	164	29/2/84	928	202	928	-	202
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	195	179	31/12/79	195		195	-	-
OTHERS	583	180		681	23	606	75	98
TOTALS	31,025	5,334		33,636	225	31,250	2,386	2,611
ROUNDED TOTALS	31,000	5,300		33,600	200	31,200	2,400	2,600

(1) ALL FIGURES ARE AS OF DECEMBER 31, 1969.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANSCANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AND THE TRANSCANADA APPLICATION AS ESTIMATED BY THE BOARD

AS OF DECEMBER 31, 1969

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES					
Now considered within economic reach			44.9		
Less: Deferred			4.0		
Total Contractable Reserves				40.9	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta requirements:					
General Requirements		7.3			
Permit-related fuel and shrinkage		1.5			
Permit requirements: To meet remaining commitments		31.0			
To meet terminal year peak day		0.2			
Total Contractable Requirements				40.0	
CONTRACTABLE SURPLUS					0.9
REMAINING REQUIREMENTS					
Total Alberta requirements for delivery	16.3				
Less: Deliveries from contractable reserves	6.6				
Deliveries required from other sources		9.7			
Total Alberta Requirements for thirtieth year peak day	5.3				
Less: Available from contractable reserves	2.2				
Required from other sources to meet thirtieth year peak day		3.1			
Total Remaining Requirements			12.8		
REMAINING AND FUTURE RESERVES					
From deferred gas available within 30 years		4.0			
From reserves now considered beyond economic reach		2.0			
From reserves providing for terminal years peak day in permits		0.2			
From gas not yet established		11.7			
Total Remaining and Future Reserves			17.9		
FUTURE SURPLUS					5.1

APPENDIX F

FORM OF TYPICAL LETTER TO PERMITTEE RE CERTAIN TRANSMISSION AND REPROCESSING REQUIREMENTS

Dear Sirs:

The Board has, as a result of requests from certain permittees removing gas from the Province, given consideration to its methods of providing for Trunk Line fuel and losses and for fuel and shrinkage at reprocessing plants. The Board is satisfied that the uses referred to above are properly classified as "Alberta requirements" and as such need not be provided for from the volume specified in permits for removal from the Province. These requirements may be met from any source in Alberta. The only problem appears to be one associated with identifying the gas that is used for those Alberta requirements and that which is removed from the Province.

The Board believes that the problem would be resolved by the introduction into the permit of a clause such as

> For the purposes of this permit, where gas acquired by the Permittee from fields other than those named in clause_______ is commingled in transmission with gas acquired from pools, fields and areas named in clause______, such gas from fields other than those named in clause______shall be deemed to be used first to supply sales to consumers, communities and utilities in Alberta, Trunk Line fuel and losses and fuel and shrinkage at reprocessing plants.

The Board would be prepared to consider an application for the addition of such a clause at the time of the next application by the permittee for an amendment to its permit. The Board does not consider the matter to be urgent.

The Board believes Trunk Line fuel and losses and fuel and shrinkage at the ________________ reprocessing plant are somewhat different from normal domestic, commercial and industrial Alberta requirements since all the former are directly dependent on the removal of gas from the Province. For this reason the Board intends in the future to segregate this portion of Alberta requirements from the normal Alberta requirements in calculating the contractable Alberta surplus. Additionally, in the future an applicant for a permit or an amendment to a permit will be required to satisfy the Board that suitable arrangements have been made for the purchase of the volumes of gas needed for the application-related fuel and shrinkage. Such volumes need not be available from permit fields. In cases where the applicant does not demonstrate that suitable arrangements have been made for the fuel, shrinkage and losses associated with the removal from the Province of the gas applied for, the Board, in determining the volumes of gas available to the applicant, would assume that these requirements would be satisfied from the permit fields and reduce accordingly the volumes authorized for removal from the Province.

Mr. G. J. DeSorcy, Manager of the Board's Gas Department, will be pleased to discuss any details of these matters with you.

Yours sincerely,

G. W. Govier
Chairman

APPENDIX G

FORM OF PERMIT

IN THE MATTER of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Trans-Canada Pipe Lines Limited authorizing the removal of gas from the Province

PERMIT NO. TC 70-10

WHEREAS Trans-Canada Pipe Lines Limited (hereinafter called "the Permittee") is removing gas from the Province under the authority of Permit No. TC 69-9; and

WHEREAS the Permittee has applied to the Oil and Gas Conservation Board for an increase in the volumes of gas that it may remove or cause to be removed from the Province, and for amendment and consolidation of its permit; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the Permittee is a person who appears to have made arrangements to purchase gas within the Province and who proposes to remove such gas from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this Permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province and to the established

reserves and the trends in growth and discovery of reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by an Order in Council, numbered O.C. and dated

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, hereby grants a permit to Trans-Canada Pipe Lines Limited, and hereby authorizes the removal of gas from the Province, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on the date hereof and ending on October 31, 1994.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed

(a) a total quantity of 22,360,000,000,000 cubic feet less the quantity removed from the Province under permits of which Trans-Canada Pipe Lines Limited was at any time the permittee, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending October 31, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 3,118,000,000 cubic feet and in a 12-month period such rates shall not exceed 1,002,000,000,000 cubic feet.

3. The quantity of gas that may be removed from the Province in accordance with clause 2, subclause (b), during any 12-month period ending October 31, may be augmented by any part of the quantity by which gas removed from the Province under this Permit, Permit No. TC 64-6, Permit No. TC 67-7, Permit No. TC 68-8, Permit No. PG 64-1 or Permit No. TC 69-9 in the last preceding four-year period ending October 31, shall have been less than the sum of the annual volumes stipulated in clauses 2 of the permit or permits to be so removed in the four-year period and which has not, in the meantime, been removed from the Province as an augmentation authorized by this clause, but nothing herein authorizes the removal of gas from the Province in any consecutive 24-hour period or during the term of the Permit in excess of the volumes stipulated for such periods in clause 2.

4. Notwithstanding the provisions of clause 2, subclause (b), the Permittee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the

volume of gas authorized by said sub-clause (b).

4. The Permittee, subject to clause 8, may remove or cause to be removed from the Province under the authority of this Permit, only gas produced from the following pools, fields and areas:

Alderson Field
Alix Field
Amisk Field
Armada Field
Atlee-Buffalo Field
Bantry Field
Bashaw Field
Bassano Field
Bellis Field
Berry Field
Big Bend Field
Bindloss Field
Birch Field
Black Diamond Field
Blueridge Field
Boyle Field
Brazeau River Field
Bruce Field
Burnt Timber Field
Caroline Viking A Pool
Caroline Viking E Pool
Caroline Basal Mannville A Pool
Carstairs Field
Cassils Field
Castor Field
Cessford Field
Chestermere Field
Chigwell Field
Clive Field
Connorsville Field
Countess Field
Craigend Field
Crossfield Field
Crossfield East Field
Drumheller Field
Edson Field
Enchant Field
Equity Field

Erskine Field
Fenn West Field
Ferrier Field
Figure Lake Field
Flat Field
Garrington Mannville A Pool
Garrington Leduc A Pool
Ghost Pine Field
Gilby Field
Goodwin Field
Greencourt Field
Hackett Field
Halliday Field
Harmattan East Field
Harmattan-Elkton Rundle A Pool
Highland Field
Homeglen Rimbey Field
Hughenden Field
Hunter Valley Field
Hussar Field
Innisfail Field
Jarrow Field
Jenner Field
Johnson Field
Jumping Pound West Field
Killam Field
Kitsim Field

Lathom Field
Leckie Field
Little Bow Field
Lone Pine Creek Field
Long Coulee Field
Lookout Butte Field
Malmo Field
Marten Hills Field
McMullen Field
Medicine River Field
Mikwan Field
Mikwan South Field
Mitsue Field
Moose Field
Nevis Field
Newell Field
New Norway Field
Nipisi Field
Obed Field
Olds Field
Oyen Field
Oyen South Field
Parflesh Field
Pelican Field
Pincher Creek Field
Plain Field
Prevo Field

Princess Field

Provost Field

Quirk Creek Field

Rainier Field

Ranfurly Field

Retlaw Field

Rich Field

Richdale Field

Ricinus Field

Rowley Field

Scandia Field

Sedalia Field

Sedgewick Field

Seiu Lake Field

Sibbald Field

Standard Field

Strachan Field

Sundre Basal Mannville A Pool

Sundre Basal Mannville B Pool

Sunnynook Field

Superba Field

Swalwell Field

Sylvan Lake Field

Three Hills Creek Field

Trochu Field

Turin Field

Twining North Field

Ukalta Field

Verger Field

Vulcan Field

Warwick Field

Wayne-Rosedale Field

Westerose Field

Westerose South Field

Whiskey Field

Whitecourt Field

Wildhorse Creek Field

Wildunn Creek Field

Willesden Green Field

Wimborne Field

Winnifred Field

Wintering Hills Field

Wood River Field

The area in the Medicine Hat Field being north of Sections 1 to 6 inclusive, in Township 15, and in Ranges 1 to 3 inclusive, West of the 4th Meridian, excepting therefrom Section 7, Township 15, Range 2, West of the 4th Meridian.

6. (1) The Permittee shall satisfy the Board prior to November 1, 1970, or such later date as the Board upon application by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Bruce Field, the Flat Field, the Jarrow Field and the Killam Field or from a substantial part of each of the fields; and

(b) the Permittee has elected to cause the construction of the Bruce-Birch Lake Line or has advised the sellers under the contracts referred to in subclause (a) that it is proceeding to cause the Marten Hills Line to be constructed; and

(c) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1971, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

7. (1) The Permittee shall satisfy the Board prior to November 1, 1971, or such later date as the Board upon application by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Amisk Field, Big Bend Field, Black Diamond Field, Castor Field, Chestermere Field, Hughenden Field, Jumping Pound West Field, McMullen Field, Pelican Field, Provost Field and Turin Field or from a substantial part of each of the fields; and

(b) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1972, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

8. Gas acquired in Alberta by the Permittee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 5, may be removed from the Province under the authority of this Permit.

9. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered to it through facilities of The Alberta Gas Trunk Line Company Limited at the interconnections of their pipe lines in the North-east quarter of Section 11 and the South-west quarter of Section 12, both in Township 20, Range 1, West of the 4th Meridian and in the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian.

10. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the points at which gas is delivered in accordance with clause 9 by The Alberta Gas Trunk Line Company Limited to the Permittee.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the points at

which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

11. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

12. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

13. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

14. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 13, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from

the capable source or sources available to the Permittee nearest to the point of delivery.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

16. Permit No. TC 69-9 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of , A. D. 1970.

OIL AND GAS CONSERVATION BOARD

G. W. Govier
Chairman